BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39 M) to Submit Its 2024 Risk Assessment and Mitigation Phase Report	Application No. 24-05-___

APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY (U39M) TO SUBMIT ITS 2024 RISK ASSESSMENT AND MITIGATION PHASE (RAMP) REPORT

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Dated: May 15, 2024

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company (U 39 M) to Submit Its 2024 Risk Assessment and Mitigation Phase Report	Application No. 24-05-___ (Filed May 15, 2024)

APPLICATION OF PACIFIC GAS AND ELECTRIC COMPANY (U39M) TO SUBMIT ITS 2024 RISK ASSESSMENT AND MITIGATION PHASE (RAMP) REPORT

Pacific Gas and Electric Company (PG&E) hereby respectfully submits its 2024 Risk Assessment and Mitigation Phase (RAMP) Report. The 2024 RAMP Report provides a quantitative assessment of the Company's top twelve safety risks; describes preliminary mitigation plans; and estimates the costs and benefits associated with mitigating these risks. The Report is submitted pursuant to the Commission's direction in D.20-01-002[1] and constitutes the initial phase of PG&E's 2027 General Rate Case (GRC). PG&E will file its 2027 test year GRC application on May 15, 2025. The 2024 RAMP report is PG&E's third RAMP filing, following the 2017 and 2020 RAMP Reports.

I. OVERVIEW OF PG&E'S 2024 RAMP REPORT

The 2024 RAMP Report represents progress on the joint efforts of the Commission and Safety Policy Division (SPD),[2] PG&E, California's other large investor owned- utilities (IOUs), and other stakeholders over the past several years to enhance risk-informed decision-making through the Safety Model Assessment Phase (S-MAP) proceeding;[3] the Order Instituting Rulemaking (OIR) to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities Proceeding (Risk OIR);[4] and the IOUs' respective RAMP Reports. These joint efforts recently culminated in the Risk

1 D.20-01-002, p. 49.

2 The SPD assumed the role of developing and recommending safety policy concerning risk assessment and risk mitigation from the SED.

3 The May 1, 2015 S-MAP applications by each of the large utilities were consolidated on June 19, 2015 and were resolved in D.18-12-014 "Phase Two Decision Adopting Safety Model Assessment Proceeding (S-MAP) Settlement Agreement With Modifications."

4 Rulemaking (R.) 20-07-013.

OIR Phase I and Phase II Decisions.[5] PG&E is the first utility to submit a RAMP under the new requirements of these decisions, and the 2024 RAMP Report reflects PG&E's initial implementation of the methodologies adopted in those decisions.

A. PG&E's Implementation of the Risk OIR Phase II Decision (D.22-12-027)

A major development in the Risk OIR Phase II decision was the superseding of the S-MAP Settlement Agreement adopted in D.18-12-014 with the Risk-Based Decision-Making Framework (RDF).[6] In the 2024 RAMP Report, PG&E has built its Cost Benefit Approach (CBA)[7] following the principles adopted as part of the RDF.[8] Using that methodology, PG&E performed a risk analysis of the Enterprise Risks on its Corporate Risk Register, and used the calculated Risk Values to identify and rank its top safety risks to be evaluated in RAMP, and to develop the proposed mitigations to address those risks. PG&E's 2024 RAMP Risks are shown in Section I.C below.

The central feature of the CBA is reporting risk in monetized terms, i.e., dollars. Previously, under the S-MAP Settlement Agreement, risk was reported in "scaled units." Citing clarity, transparency and other benefits, the Commission stated that reporting risk in dollars will "result in utility risk and Mitigation Benefit calculations that are more useful during review and consideration of RAMP and GRC filings."[9] PG&E's CBA implementation follows the Commission's guidance and includes the following elements:

- Introduction of reliability-induced, indirect safety under the Safety Attribute, resulting in safety scores that include the potential indirect safety impacts from extended-duration electric outages.
- Adoption of Commission guidance in determining a standard dollar value of safety, electric reliability, and gas reliability attributes.

5 D.21-11-009, "Decision Addressing Phase I, Track 1 and 2 Issues"; and D.22-12-027 "Phase II Decision Adopting Modifications to the Risk-Based Decision-Making Framework Adopted in Decision 18-12-014 and Directing Environmental and Social Justice Pilots."

6 D.22-12-027 Appendix A – Risk-Based Decision-Making Framework.

7 D.22-12-027, Appendix A, p. A-3 defines a CBA as: "[a] decision-analysis tool for comparing the monetized Benefits of a program, or set of activities, against the costs of the program, or set of activities, to create a measurement of value."

8 See PG&E RAMP Report, Exhibit (PG&E-2), Ch. 2, "Risk Modeling and Cost-Benefit Ratio."

9 D.22-12-027, p. 26.

- Adoption of an objective risk-scaling function that represents societal risk preferences using a market-based approach.

In addition, as directed by D.22-12-027,[10] PG&E developed an Environmental and Social Justice (ESJ) Pilot Study Plan (PSP) and includes in the 2024 RAMP Report the initial results of implementing the PSP.

B. PG&E's Implementation of the Risk OIR Phase I Track 1 Decision (D.21-11-009)

In D.21-11-009, the Commission provided guidance and requirements pertaining to the IOUs' RAMP and GRC filings. The major impacts to the 2024 RAMP are:

<u>Modeling PSPS Events as Risk Events</u>: D.21-11-009 states: "Each IOU shall model Public Safety Power Shutoff (PSPS) events as risk events pursuant to requirements in D.18-12-014."[11] As directed, in the 2024 RAMP, the Wildfire Risk is now included as "Wildfire with PSPS and EPSS."[12] PG&E maintains that PSPS (and Enhanced Powerline Safety Settings (EPSS)) are mitigations for Wildfires and thus their benefits and consequences should be considered in the overall Wildfire Risk analysis since PSPS is a last-resort safety measure taken to help prevent catastrophic wildfires by turning off power during dry, windy weather (and EPSS is also a measure taken to prevent ignitions by quickly turning off power when high-impedance faults are detected). However, to help better understand and manage the risk from the PSPS and EPSS, PG&E has separated PSPS and EPSS into their own Bow Ties and analyzed them as risk events.

<u>PG&E Transparency Proposal</u>: D.21-11-009, required Southern California Edison Company (SCE) to "test drive" PG&E's Transparency Proposal that was presented to address Transparency and Uncertainty in Track 1 of Risk OIR Phase 1, Application (A.) 20-07-013.[13] The proposal was created to address "[T]he inclusion of sufficient documentation in RAMP and other IOU filings for parties and Staff to understand methodologies, the quality of data, and any assumptions used."[14] On April 26, 2024,

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[10] D.22-12-027, pp. 65-67, Ordering Paragraph (OP) 5.

[11] D.21-11-009, p. 142, OP 1h.

[12] PG&E RAMP Report, Exhibit (PG&E-4), Ch. 1.

[13] The proposal was presented in the Technical Working Group of Risk OIR Phase 1. This was adopted with modifications in Track 1 Decision, D.21-11-009, p. 143, OP 3..

[14] D.21-11-009, p. 34.

the CPUC issued a proposed decision requiring the Transparency Proposal as a part of an IOU's RAMP filing moving forward, as well as requiring new elements in the analysis. PG&E is committed to providing a transparency analysis as a part of the 2024 RAMP/2027 GRC proceeding. At a later date, PG&E expects to provide its transparency analysis addressing the required elements as adopted in the Commission's final decision.

C. 2024 RAMP Risks

For the 2024 RAMP, PG&E assessed its top Safety Risks based on the criteria established in Step 2B, Element No. 12 of the RDF, resulting in the selection presented in Table 1 below.[15] For 2024, two new RAMP risks are Electric Transmission Systemwide Blackout and Cybersecurity Risk Event. Both risks are included in the 2024 RAMP largely due to the inclusion of the potential indirect safety consequences associated with long-duration loss of electric service. Two risks that were included in the 2020 RAMP but are no longer within the Top 40 Percent of Risks by Safety Value Criteria, and thus excluded in the 2024 RAMP, are Real Estate and Facilities Failure risk and Motor Vehicle Safety Incident risk.

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[15] See PG&E RAMP Report, Exhibit (PG&E-2), Ch. 4, "RAMP Risk Selection".

TABLE 1
PG&E'S 2024 RAMP RISKS

Safety Rank	Risk Name	Definition
1	Wildfire with PSPS and EPSS	The Baseline Wildfire Risk is defined as a wildfire that may endanger the public, private property, sensitive lands or environment originating from PG&E assets or activities. In the near term due to the use of PSPS and EPSS we have also defined Post PSPS/EPSS Wildfire Risk as Wildfire Risk with PSPS and EPSS. This does account for the benefits and consequences of operational mitigations such as PSPS and EPSS.
2	Loss of Containment (LOC) on Gas Transmission Pipeline	Failure of a gas transmission pipeline resulting in a LOC, with or without ignition, that could lead to significant impact on public safety, employee safety, contractor safety, property damage, financial loss, or the inability to deliver natural gas to customers. Failure of a gas transmission pipeline includes both pipeline leak and pipeline rupture.
3	Public Contact with Intact Energized Electrical Equipment (PCEEE)	PCEEE is defined as the risk of recordable serious injury or fatality to a third-party contractor or member of the public from an interaction with intact PG&E electric assets that did not originate from asset failure.
4	Failure of Electric Distribution Overhead Assets	Failure of Distribution Overhead Assets or lack of remote operational functionality may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy.
5	Electric Transmission Systemwide Blackout	A system wide disturbance leading to a cascading event that causes a blackout of PG&E's electrical system, with the inability to restore the grid in a timely fashion.
6	Contractor Safety Incident	Any event resulting in a contractor serious injury or fatality as defined by PG&E's Serious Injury and Fatality (SIF) Standard which is aligned with the Edison Electric Institute (EEI) International Safety Classification and Learning (SCL) Model.
7	Employee Safety Incident	Any event resulting in: (1) a serious injury or fatality as defined by PG&E's SIF Standard which is aligned with the EEI SCL model or (2) a Days Away, Restricted, or Transferred incident as defined by the Occupational Safety and Health Administration.
8	Cybersecurity Risk Event	A coordinated malicious attack targeting PG&E's core business functions, resulting in disruption or damage of systems used for gas, electric and/or business operations.
9	Large Uncontrolled Water Release (Dam Failure)	Failure of a high or significant hazard dam, where failure or mis-operation could cause loss of human life and/or could cause economic loss, environmental damage, disruption of lifeline facilities, and other concerns.
10	Failure of Electric Distribution Underground Assets	The failure of distribution underground (including radial and network) assets or lack of remote operation functionality may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy.
11	LOC on Gas Distribution Main or Service	Failure of a gas distribution main or service resulting in a LOC, with or without ignition, that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, or the inability to deliver natural gas (NG) to customers.
12	Large Overpressure Event Downstream of Gas Measurement and Control (M&C) Facility	Failure of a gas M&C facility to perform its pressure control function resulting in a large overpressure event downstream that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, and/or the inability to deliver natural gas to customers.

D. Public Workshops and Modifications.

Leading up to filing of this Report, PG&E conducted two public workshops to discuss PG&E's selection of risks to be included in this Report and to demonstrate its implementation of the Cost-Benefit Approach in accordance with the RDF Proceeding Phase II Decision.

PG&E's first workshop was held on February 7, 2024, two weeks following the dissemination of PG&E's 2024 RAMP Preliminary Risks list. The purpose of this workshop was "to gather input from SPD, other interested CPUC staff, and interested parties to inform the determination of the final list of risks to be included in the RAMP."[16] In this workshop, PG&E presented the data, assumptions, and bow tie elements for each of the twelve preliminary RAMP risks. PG&E also provided a comparison of the 2020 RAMP risks to the 2024 RAMP preliminary risks. PG&E received feedback from The Utility Reform Network (TURN), Mussey Grade Road Alliance (MGRA) and SPD, and discusses in the RAMP Report PG&E's responses to the input provided.[17]

PG&E presented its CBA implementation at a public workshop hosted by the SPD on April 11, 2024, as directed by D.22-12-027 Ordering Paragraph 3. Feedback was received from TURN, California Public Advocates, MGRA and SPD. In its RAMP Report PG&E addresses modeling-related concerns raised by the parties and provides additional clarification to answers provided at the session.[18]

II. STRUCTURE OF PG&E'S 2024 RAMP REPORT

Consistent with the direction provided in the RDF Phase I decision, PG&E's 2024 RAMP Report is organized into exhibits and chapters as shown in the Table 2 below.[19] The Report includes a separate chapter for each of PG&E's twelve RAMP risks. Each risk is presented in a standard format with the same elements.

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16 D.22-12-027, Appendix A, p. A-12, No. 12.

17 RAMP Report, Exhibit (PG&E-2), Ch. 4, Section D.

18 RAMP Report, Exhibit (PG&E-2), Ch. 2, Section F.

19 These Exhibit numbers are consistent with PG&E's GRC Exhibit numbers to allow for mapping of RAMP risk mitigations to GRC testimony and workpapers. D. 20-01-002, p. 61.

TABLE 2
PG&E'S 2024 RAMP REPORT STRUCTURE

RAMP Report Exhibit	Chapter	Contents
Exhibit (PG&E-1)	1	Introduction
Exhibit (PG&E-2): Risk Management, Safety, and Planning	1	Risk Management Framework
	2	Risk Modeling and CBR
	3	Cross-Cutting Factors
	4	RAMP Risk Selection
	5	Safety Culture, Policy, and Compensation
	6	Climate Resilience
	7	Environmental and Social Justice (ESJ) Pilot Study Plan (PSP) Implementation
Exhibit (PG&E-3): Gas Operations RAMP Risks	1	Loss of Containment (LOC) on Gas Transmission Pipeline
	2	LOC on Gas Distribution Main or Service
	3	Large Overpressure Event Downstream of Gas Measurement and Control (M&C) Facility
Exhibit (PG&E-4): Electric Operations RAMP Risks	1	Wildfire with PSPS and EPSS
	2	Electric Transmission Systemwide Blackout
	3	Public Contact with Intact Energized Electrical Equipment (PCEEE)
	4	Failure of Electric Distribution Overhead Assets
	5	Failure of Electric Distribution Underground Assets
Exhibit (PG&E-5): Energy Supply RAMP Risks	1	Large Uncontrolled Water Release (Dam Failure)
Exhibit (PG&E-7): Enterprise Health and Safety, Information Technology, and Shared Services RAMP Risks	1	Contractor Safety Incident
	2	Cybersecurity Risk Event
	3	Employee Safety Incident
Appendix A		ESJ PSP
Appendix B		Risk Modeling Acronyms

Concurrent with filing of this application, PG&E is serving workpapers supporting each of its twelve RAMP risk models and their mitigation and control Cost Benefit Ratios (CBRs) along with Model User Guides. These workpapers are described in Exhibit (PG&E-2) Chapter 2, Section E of the RAMP Report.

III. RELIEF SOUGHT

PG&E respectfully requests:

1. The Commission direct the SPD to review PG&E's RAMP Report and issue a report by September 3, 2024 (i.e., 110 days after the filing of this application)[20] consistent with the requirements of D.14-12-025 and D.20-01-002; and
2. The Commission close this proceeding upon such time as PG&E has integrated the RAMP Report methodologies, and the requisite changes resulting from the SPD evaluation, into PG&E's upcoming 2027 GRC proceeding.

IV. STATUTORY AND PROCEDURAL REQUIREMENTS

A. Statutory and Other Authority.

PG&E files this application pursuant to D.18-12-014 and D.20-01-002; Section 701 of the California Public Utilities Code; as well as Rule 2.1 of the Commission's Rules of Practice and Procedure. This 2024 RAMP Report submission has been verified by a PG&E officer, consistent with Rule 1.11.

B. Legal Name and Principal Place of Business – Rule 2.1(a).

The legal name of the Applicant is Pacific Gas and Electric Company. PG&E's principal place of business is 300 Lakeside Drive, Oakland, CA 94612. Its post office address is Post Office Box 1018, Oakland, California 94604.

C. Correspondence and Communication Regarding this Application – Rule 2.1(b).

All correspondence and communication regarding this Application should be addressed to Peter Ouborg and Ken Arnold as shown below:

[20] D. 20-01-002, Appendix A, Table 1, "Adopted Revised GRC Application Filing Schedule".

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D. Categorization - Rule 2.1(c).

PG&E proposes that this Application be categorized as a "ratesetting" proceeding pursuant to Commission Rule of Practice and Procedure 1.3(g) and 7.1(e)(2).

E. Need for Hearing - Rule 2.1(c).

PG&E believes that evidentiary hearings on PG&E's RAMP are unnecessary and notes that evidentiary hearings are not contemplated by the Commission's proceeding schedule in D.20-01-002, Appendix A.

F. Issues to be Considered - Rule 2.1(c).

The principal issues to be considered are whether:

1. The Commission should direct SPD or other appropriate Commission staff to evaluate and issue a report on PG&E's RAMP Report; and
2. The Commission should close this proceeding following PG&E's integration of the RAMP Report and potential changes as a result of SPD's evaluation and other parties' comments into PG&E's 2027 GRC proceeding.

G. Relevant Safety Considerations – Rule 2.1 (c).

In D.16-01-017, the Commission adopted an amendment to Rule 2.1(c) requiring utilities' applications to clearly state the relevant safety considerations. The Commission has previously explained that the "safe and reliable provision of utilities at predictable rates promotes public safety."[21]

Safety is the foremost issue in this Application. PG&E's RAMP focuses on safety and effective risk mitigation to further reduce risk to PG&E employees, contractors, and the public. It includes PG&E's analysis of its top enterprise safety risks and PG&E's preliminary plans to mitigate those risks from 2024 to 2030. This assessment is a first step to PG&E's risk-informed spending forecasts that will be presented in its 2027 GRC.

H. Proposed Procedural Schedule (Rule 2.1(c)).

Commission Rule 2.1(c) requires that all Applications state "the proposed category for the proceeding, the need for hearing, the issues to be considered including relevant safety considerations, and a proposed schedule." PG&E's proposed schedule is set forth below and is based on the Commission's "Adopted Revised GRC Application Filing Schedule."[22] In addition, because D.14-12-025 also includes two public workshops in the RAMP schedule (one following a utility's RAMP submission and another following the issuance of the Commission Staff report), PG&E has included proposed dates for those events. Finally, adhering to this schedule is important, because doing so will provide the time necessary for PG&E to consider SPD's findings and parties' comments on its proposed mitigations and associated spending in the preparation of PG&E's 2027 GRC forecast.

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[21] D.14-12-053, pp. 12-13.

[22] D. 20-01-002, Appendix A, Table 1.

TABLE 3
PROPOSED PROCEDURAL SCHEDULE

Activity	Proposed Date
PG&E's 2024 RAMP Application Filed	May 15, 2024
PG&E and SPD Post-Report Workshop	June 5, 2024
Protests or Responses	30 days from Notice of Filing of Application
Reply to Protests or Responses	10 days from last day for Filing Protests and Responses
Prehearing Conference	July 8, 2024
SPD Files and Serves Report on PG&E's 2024 RAMP submission	September 3, 2024
Opening Comments on SPD Report	November 15, 2024
Reply Comments	December 2, 2024
PG&E files Test Year 2027 GRC Application	May 15, 2025

I. Articles of Incorporation (Rule 2.2).

PG&E is, and since October 10, 1905, has been, an operating public utility corporation organized under California law. PG&E is engaged principally in the business of furnishing electric and gas services in California. A copy of PG&E's Amended and Restated Articles of Incorporation, effective June 22, 2020, is on record before the Commission in connection with PG&E's A.20-07-002, filed with the Commission on July 1, 2020, and are incorporated by reference herein.

V. SERVICE

A copy of this Application has been served on the following service lists:

1. A.21-06-021 (PG&E's 2023 General Rate Case Application);
2. Rulemaking (R.) 20-07-013 (Order Instituting Rulemaking to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities Proceeding); and
3. Rulemaking (R.) 18-04-019 (Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Change Adaptation).

PG&E is serving a Notice of Availability of the RAMP Report and supporting workpapers to the above service lists.

VI. CONCLUSION

PG&E respectfully requests that the Commission direct SPD to issue a report on its evaluation of PG&E's 2024 RAMP Report by September 3, 2024; and close this proceeding following PG&E's integration of the RAMP Report and potential changes resulting from the SED Report evaluation into the 2023 GRC proceeding.

Respectfully submitted,

By: *__/s/ Peter Ouborg__*
PETER OUBORG

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Attorney for
PACIFIC GAS AND ELECTRIC COMPANY

Dated: May 15, 2024

VERIFICATION

I, Alejandro Vallejo, hereby declare that I am the Chief Risk Officer and Senior Vice President of Ethics and Compliance at Pacific Gas and Electric Company and am authorized to make this verification on behalf of Pacific Gas and Electric Company; that I have read the foregoing:

APPLICATION OF
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and that the information related to Pacific Gas and Electric Company set forth therein is true and correct to the best of my knowledge, information, and belief.

I declare under penalty of perjury pursuant to the laws of the state of California that the foregoing is true and correct.

Executed: May 15, 2024

/s/ Alejandro Vallejo
Alejandro Vallejo
Chief Risk Officer and Senior Vice President, Ethics and Compliance

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT
PG&E'S 2024 RAMP REPORT

Application: 24-05-
(U 39 G)
Exhibit No.: (PG&E-1)
Date: May 15, 2024
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT

EXHIBIT (PG&E-1)

INTRODUCTION

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INTRODUCTION

A. Guiding Principles

In developing Pacific Gas and Electric Company's (PG&E or the Company) Risk Assessment and Mitigation Phase (RAMP) Report (Report), PG&E has been guided by the following principles.

First, we are committed to transparency and collaboration. All parties share the RAMP's paramount goal of making safety the top priority, consistent with the principle of just and reasonable cost-based rates. In this report, we clearly and transparently explain our risk analysis and recommended mitigation strategies. This analysis is a starting point and going forward we welcome feedback and collaboration with the California Public Utilities Commission (CPUC or Commission) and stakeholders to ensure that PG&E's 2027 General Rate Case (GRC) forecast is risk-informed, prioritizes safety, and includes effective risk control and mitigation programs.

Second, driven by many factors including new demands on the utility business, a changing climate, and emerging threats such as cyber attack, our risk landscape is increasingly dynamic and evolving, and therefore our risk assessments and mitigation strategies must likewise remain flexible and nimble. The analysis and mitigation plans in this Report, by necessity, represent our best current understanding of the risks and the mitigation strategies available. The analysis and mitigation plans will continue to evolve, and could change in both scope and scale as we proceed with GRC planning, monitor our risk landscape, and adjust our risk models, financial forecasts, and work plans accordingly.

Third, we acknowledge the importance of using current quantitative models to inform our planning decisions, while also placing these analyses in the broader context of prudent utility management that includes all the factors that PG&E must weigh and balance in planning for the future. PG&E's risk management strategies must also consider factors that are either not addressed or not captured adequately in RAMP's quantitative models. Examples include: climate change that has longer trajectories and pay-offs than the 2027-2030 period; rapidly evolving risk dynamics like cybersecurity that are very difficult to forecast even in the short term; and the looming nationwide need for a greater electric grid capacity to accommodate decarbonization, electric vehicles, and significant load growth to support an expanding digital economy. We start to address these factors in this report and will further incorporate them in our 2027 GRC.

Finally, we anchor on the principle of eliminating incidents involving serious injuries or fatalities related to our assets and operations, which is consistent with PG&E's stands that "Everyone and everything is always safe" and "Catastrophic wildfires shall stop." PG&E is poignantly aware of the profound and wide-ranging impacts from low-frequency and high-consequence risk events. Accordingly, many of the work plans in this Report include mitigations that are aimed at eliminating serious safety events even when the quantitative RAMP modelling indicates the costs are higher than the modeled value of risk reduction. In Decision (D.) 22-12-027, the Commission also recognized that factors other than cost-effectiveness may influence selection of risk mitigations, specifically identifying both risk tolerance and modeling limitations and/or uncertainties as such factors.[1] In this Report we explain where these factors influenced our decision to include in our mitigation strategy risk reduction programs that may not seem cost effective under the quantitative risk modelling.

PG&E looks forward to continuing to work collaboratively and transparently with the Commission and stakeholders to address these issues in the ongoing Risk OIR, all with the shared goal of delivering energy safely, reliably, and affordably to our customers.

The remainder of this introductory chapter is organized as follows:

- An overview of the structure and requirements of the RAMP process, and how PG&E has complied with these requirements in this Report (Section B);
- Identification of the 2024 RAMP risks selected for inclusion in this Report and how they differ from the 2020 RAMP risks (Section C);

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1 D.22-12-027, Appendix A, p. A-16, No. 26, "Mitigation selection can be influenced by other factors including, but not limited to, funding, labor resources, technology, planning and construction lead time, compliance requirements, Risk Tolerance thresholds, operational and execution considerations, and modeling limitations and/or uncertainties affecting the analysis."

- A discussion of how PG&E considers the outputs of the RAMP risk analysis to develop risk mitigation work plans and cost estimates in the context of modelling limitations and uncertainty; factors other than cost-benefit ratios (CBR) impacting the selection of certain mitigations; and the planning framework for developing future investment plans (Section D); and
- A summary of lessons learned and future enhancements (Section E).

B. Overview of RAMP

This RAMP Report is submitted pursuant to the Commission's direction in D.20-01-002[2] and constitutes the initial phase of PG&E's 2027 GRC. PG&E will file its 2027 test year GRC application on May 15, 2025.

1. Procedural History

In 2011, Senate Bill 705 was enacted to address gas safety in the operations of energy utilities. Among its directives, later codified as California Public Utilities Code § 963 (b)(3), was a paramount focus on safety:

> It is the policy of the state that the commission and each gas corporation place safety of the public and gas corporation employees as the top priority. The commission shall take all reasonable and appropriate actions necessary to carry out the safety priority policy of this paragraph consistent with the principle of just and reasonable cost-based rates.[3]

Subsequently, in D.14-12-025, the Commission created the Safety Model Assessment Phase (S-MAP) and RAMP processes to incorporate a risk-based decision-making framework into the GRCs of the IOUs:

> (t)he GRC is the appropriate place to start to take all reasonable and appropriate actions necessary to carry out the safety priority policy of § 963(b)(3), consistent with the principle of just and reasonable cost-based rates.[4] [5]

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[2] D.20-01-002, p. 49.

[3] Public Utilities Code § 963(b)(3).

[4] D.14-12-025, p. 52, Conclusion of Law (COL) 1.

[5] The Commission further clarified in D.14-12.025 COL 4, "(p)ursuant to §§ 451, 701, 761, and 750 as added by SB 900, the Commission has the power to extend the risk-based decision-making framework to the GRCs of the electrical corporations."

The 2024 RAMP Report represents progress on the joint efforts of the Commission and Safety Policy Division (SPD),[6] PG&E, California's other large investor-owned utilities (IOU), and other stakeholders over the past several years to enhance risk-informed decision-making through the S-MAP, the Order Instituting Rulemaking (OIR) to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities Proceeding (Risk OIR)[7] and RAMP Reports. These joint efforts recently culminated in the Risk OIR Phase I and Phase II Decisions.[8] This Report reflects PG&E's initial implementation of the methodologies adopted in those decisions.

2. Changes Since PG&E's 2020 RAMP Report

a. PG&E's Implementation of the Risk OIR Phase II Decision (D.22-12-027)

A major development in the Risk OIR Phase II decision was the superseding of the S-MAP Settlement Agreement found in D.18-12-014 with the Risk-Based Decision-Making Framework (RDF).[9] PG&E's implementation of the RDF and the Risk OIR Phase I and Phase II Decisions is summarized below and explained further in Exhibit (PG&E-2), Chapters 2, 4, and 8 of this Report.

1) Cost-Benefit Approach

PG&E built its Cost Benefit Approach (CBA)[10] following the principles adopted as part of the RDF.[11] Using that methodology, PG&E performed a risk analysis of the Enterprise Risks on its

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6 The SPD assumed the role of developing and recommending safety policy concerning risk assessment and risk mitigation from the SED.

7 Rulemaking (R.) 20-07-013.

8 D.21-11-009, "Decision Addressing Phase I, Track 1 and 2 Issues"; and D.22-12-027 "Phase II Decision Adopting Modifications to the Risk-Based Decision-Making Framework Adopted in Decision 18-12-014 and Directing Environmental and Social Justice Pilots."

9 D.22-12-027 Appendix A – Risk-Based Decision-Making Framework.

10 D.22-12-027, Appendix A, p. A-3 defines a CBA as: "[a] decision-analysis tool for comparing the monetized Benefits of a program, or set of activities, against the costs of the program, or set of activities, to create a measurement of value."

11 See Exhibit (PG&E-2), Ch. 2, "Risk Modeling and Cost-Benefit Ratio."

Corporate Risk Register, and used the calculated Risk Values[12] to identify and rank its top safety risks, of which there are 12, to be evaluated in RAMP, and to develop the proposed mitigations to address those risks. The RAMP risks selected by PG&E for inclusion in this Report, and how those risks differ from the risks included in the 2020 RAMP Report, are discussed in Section C below.

The central feature of the CBA is reporting risk in monetized terms, i.e., dollars. Previously, with the S-MAP Settlement Agreement, risk was reported in "scaled units." Citing clarity, transparency and other benefits, the Commission stated that reporting risk in dollars will "result in utility risk and Mitigation Benefit calculations that are more useful during review and consideration of RAMP and GRC filings."[13] PG&E's CBA implementation follows the Commission's guidance and includes the following elements:

- <u>Introduction of a New Sub-Attribute Under the Safety Attribute: (Reliability-induced) Indirect Safety</u>. In D.14-12-025, the Commission stated "We recognize, however, that reliability-related issues can affect safety. In such situations, those reliability issues should be included in the assessment of safety."[14] Also, in response to the Public Advocates Office at the California Public Utilities Commission (Cal Advocates) and FEITA Bureau of Excellence, LLC's (FEITA) joint motion requesting PG&E to perform additional analysis on the full safety, health, and financial consequences of Public Safety Power Shutoff (PSPS) on its customers in PG&E's 2020 RAMP proceeding, the CPUC has required PG&E to incorporate the

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[12] PG&E uses the term "Risk Value" and "Risk Score" interchangeably throughout this report.

[13] D.22-12-027, p. 26.

[14] D.14-12-025, p. 20.

consequences of PSPS events into risk modeling.[15] Subsequently PG&E included safety consequences from reliability events in the PSPS model in its 2023 GRC and Wildfire Mitigation Plans. In this Report, PG&E has expanded the directive to include the potential indirect safety impacts from extended-duration outages.

- Adoption of Commission guidance in determining the value of Safety and Reliability Attributes. The Risk OIR Phase II decision approves the use of specific methodologies and sources of information to determine a standard dollar value of safety, electric reliability, and gas reliability attributes. For the safety attribute, PG&E used the Department of Transportation guidance for the Value of a Statistical Life (VSL), adjusted for: (1) California price and real wage data, and (2) the base year of the 2024 RAMP filing. For the electric reliability attribute, PG&E used the most current version of the Lawrence Berkeley National Laboratory Interruption Cost Estimate Calculator updated with PG&E-specific information. For the gas reliability attribute, PG&E used the implied dollar value from its 2020 RAMP (Multi-Attribute Value Function) MAVF risk score calculations, updated for the base year of the 2024 RAMP filing. One of the outcomes of applying the guidance in D.22-12-027 of using standard monetized values for Safety and Electric Reliability Attributes is that safety has becomes a smaller component of some risk values than in the 2020 RAMP. This phenomenon was discussed in the February 7, 2024 workshop and is further addressed in Exhibit (PG&E-2), Chapter 4, Section 2.a of this Report.

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15 A Joint Motion filed by Cal Advocates, and FEITA requested that PG&E analyze the full safety, health, and financial consequences of PSPS. The CPUC found it is appropriate for PG&E to provide GRC testimony concerning updated risk analysis estimating consequences of calling PSPS events. A.20-06-012, E-mail Ruling Denying Joint Motion by Public Advocates and FEITA but Requiring Updated Analysis of PSPS in the next GRC (June 3, 2021).

- Adoption of an objective Risk-Scaling Function that represents societal risk preferences using a market-based approach. PG&E used prices from insurance and capital markets to infer risk preferences, i.e., in determining the appropriate risk premiums (if any) to include when monetizing risk. As a result, PG&E's analysis can better reflect societal risk preferences by incorporating the prices that society is willing to pay to mitigate or transfer risk. This approach creates objectivity, consistency, and transparency.

A further discussion of these elements can be found in Exhibit (PG&E-2), Chapter 2.

2) Environmental and Social Justice Pilot Study Plan

As directed by D.22-12-027, PG&E has developed an Environmental and Social Justice (ESJ) Pilot Study Plan (PSP). In Exhibit (PG&E-2), Chapter 8 of this Report, we present our ESJ PSP addressing the following seven action items from D.22-12-027:

- Action Item #1: Consider equity in the evaluation of consequences and risk mitigation within the Risk-Based Decision-Making Framework, using the most current version of CalEnviroScreen to better understand how risks may disproportionately impact some communities more than others;
- Action Item #2: Consider investments in clean energy resources in the RDF, as possible means to improve safety and reliability and mitigate risks in Disadvantaged and Vulnerable Communities (DVC);
- Action Item #3: Consider mitigations that improve local air quality and public health in the RDF, including supporting data collection efforts associated with Assembly Bill 617 regarding community air protection program;
- Action Item #4: Evaluate how the selection of proposed mitigations in the RDF may impact climate resiliency in DVCs;
- Action Item #5: Evaluate if estimated impacts of wildfire smoke included in the RDF disproportionately impact DVCs;

- Action Item #6: Estimate the extent to which risk mitigation investments included in the RDF impact and benefit DVCs independently and in relation to non-DVCs in the IOU service territory; and
- Action Item #7: Enhance outreach and public participation opportunities for DVCs to meaningfully participate in risk mitigation and climate adaptation activities consistent with D.20-08-046.[16]

b. PG&E's Implementation of the Risk OIR Phase I Track 1 Decision

In D.21-11-009, the Commission provided guidance and requirements pertaining to the IOUs' RAMP and GRC filings. The major impacts to the 2024 RAMP are:

- Modeling PSPS Events as Risk Events: D.21-11-009 states: "Each IOU shall model Public Safety Power Shutoff (PSPS) events as risk events pursuant to requirements in D.18-12-014."[17] Prior to this decision, in its 2020 RAMP, PG&E modeled PSPS as a mitigation for Wildfire Risks, but also modeled the reliability impacts of PSPS in MAVF to net out the wildfire risk reduction benefits in Risk Spend Efficiency (RSE) calculation for PSPS. In its subsequent 2023 GRC filing, PG&E provided analysis of PSPS as a risk event itself, consistent with OP 1h's requirement. Here, in the 2024 RAMP, the Wildfire Risk is now included as "Wildfire with PSPS and EPSS." PG&E maintains that PSPS (and Enhanced Powerline Safety Settings (EPSS)) are mitigations for Wildfires and thus their benefits and consequences should be considered in the overall Wildfire Risk analysis since PSPS is a last-resort safety measure taken to help prevent catastrophic wildfires by turning off power during dry, windy weather (and EPSS is also a measure taken to prevent ignitions by quickly turning off power when high-impedance faults are detected). However, to help better understand and manage the risk from PSPS and EPSS, PG&E has separated PSPS and EPSS into their own

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16 D.22-12-027, pp. 65-67, Ordering Paragraph (OP) 5.

17 D.21-11-009, p. 142, OP 1h.

Bow Ties and analyzed them as risk events, per OP 1h. Exhibit (PG&E-4), Chapter 1 includes the Bow Tie analysis of not only "Wildfire Risk (without PSPS and EPSS)," but also PSPS, EPSS and "Wildfire Risk with PSPS and EPSS."

- PG&E Transparency Proposal: D.21-11-009, required Southern California Edison Company (SCE) to "test drive" PG&E's Transparency Proposal that was presented to address Transparency and Uncertainty in Track 1 of Risk OIR Phase 1, Application 20-07-013.[18] The proposal was created to address:

  > [T]he inclusion of sufficient documentation in RAMP and other IOU filings for parties and Staff to understand methodologies, the quality of data, and any assumptions used.[19]

  In Phase III of the Risk OIR, a workshop was held by SPD to review SCE's "test drive" results and discuss further refinements to PG&E's proposal. On April 26, 2024, the CPUC issued a proposed decision requiring the Transparency Proposal as a part of an IOU's RAMP filing moving forward, as well as requiring new elements in the analysis. PG&E is committed to providing a transparency analysis as a part of the 2024 RAMP/2027 GRC proceeding. At a later date, PG&E expects to provide its transparency analysis addressing the required elements as adopted in the Commission's final decision.

C. 2024 RAMP Risks

For the 2024 RAMP, PG&E assessed its top Safety Risks based on the criteria established in Step 2B, Element No. 12 of the RDF, resulting in the selection presented in Table 1-1 below. More details on PG&E's RAMP Risk selection process are presented in Exhibit (PG&E-2), Chapter 4. As can be seen in Figure 1-1 below, the 2024 RAMP risks are very similar to the 2020 RAMP risks except for two new risks that have been added in 2024 and two 2020 RAMP risks that no longer meet the criteria for inclusion as RAMP risks.

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18 The proposal was presented in the Technical Working Group of Risk OIR Phase 1. This was adopted with modifications in Track 1 Decision, D.21-11-009, p. 143, OP 3.

19 D.21-11-009, p. 34.

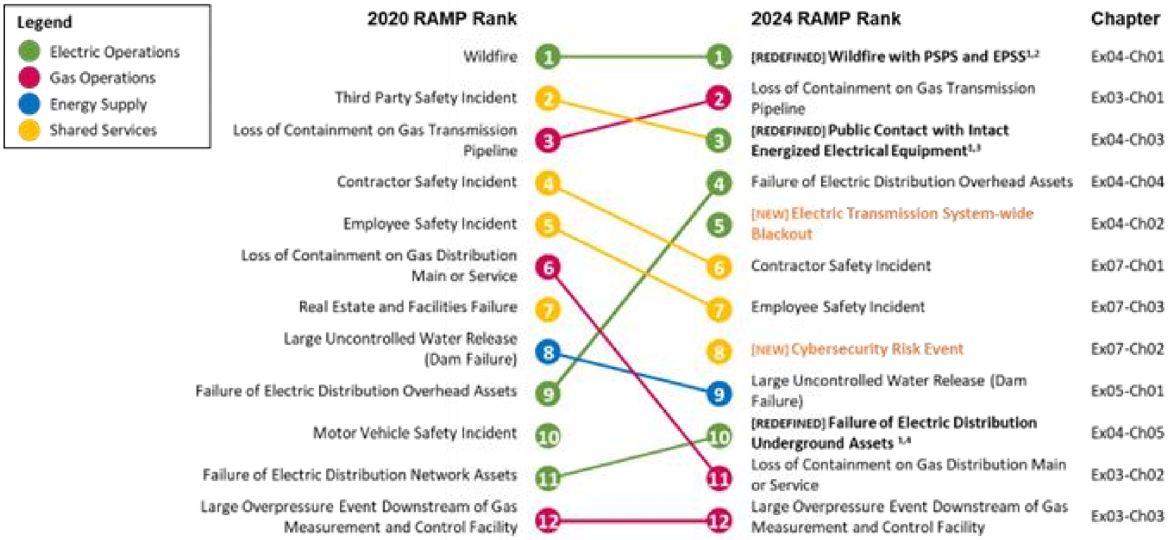
The two new RAMP risks are Electric Transmission Systemwide Blackout and Cybersecurity Risk Event. Electric Transmission Systemwide Blackout is defined as: a systemwide disturbance leading to a cascading event that causes a blackout of PG&E's electrical system, with the inability to restore the grid in a timely fashion. Cybersecurity Risk Event is defined as: a coordinated malicious attack targeting PG&E's core business functions, resulting in disruption or damage of systems used for gas, electric and/or business operations. Both risks are included in the 2024 RAMP largely due to the inclusion of the potential indirect safety consequences associated with long-duration loss of electric service.

The two risks that were included in the 2020 RAMP but are no longer within the Top 40 Percent of Risks by Safety Value Criteria, and thus excluded in the 2024 RAMP, are Real Estate and Facilities Failure risk and Motor Vehicle Safety Incident risk.

TABLE 1-1
2024 RAMP RISKS, DEFINITIONS, AND CHAPTER LOCATIONS

Line No.	Risk Name	Definition	Location
1	Loss of Containment (LOC) on Gas Transmission Pipeline	Failure of a gas transmission pipeline resulting in a LOC, with or without ignition, that could lead to significant impact on public safety, employee safety, contractor safety, property damage, financial loss, or the inability to deliver natural gas to customers. Failure of a gas transmission pipeline includes both pipeline leak and pipeline rupture.	Exhibit (PG&E-3), Chapter 1
2	LOC on Gas Distribution Main or Service	Failure of a gas distribution main or service resulting in a LOC, with or without ignition, that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, or the inability to deliver natural gas (NG) to customers.	Exhibit (PG&E-3), Chapter 2
3	Large Overpressure Event Downstream of Gas Measurement and Control (M&C) Facility	Failure of a gas M&C facility to perform its pressure control function resulting in a large overpressure event downstream that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, and/or the inability to deliver natural gas to customers.	Exhibit (PG&E-3), Chapter 3
4	Wildfire with PSPS and EPSS	The Baseline Wildfire Risk is defined as a wildfire that may endanger the public, private property, sensitive lands or environment originating from PG&E assets or activities. In the near term due to the use of PSPS and EPSS we have also defined Post PSPS/EPSS Wildfire Risk as Wildfire Risk with PSPS and EPSS. This does account for the benefits and consequences of operational mitigations such as PSPS and EPSS.	Exhibit (PG&E-4), Chapter 1
5	Electric Transmission Systemwide Blackout	A system wide disturbance leading to a cascading event that causes a blackout of PG&E's electrical system, with the inability to restore the grid in a timely fashion.	Exhibit (PG&E-4), Chapter 2
6	Public Contact with Intact Energized Electrical Equipment (PCEEE)	PCEEE is defined as the risk of recordable serious injury or fatality to a third-party contractor or member of the public from an interaction with intact PG&E electric assets that did not originate from asset failure.	Exhibit (PG&E-4), Chapter 3
7	Failure of Electric Distribution Overhead Assets	Failure of Electric Distribution Overhead Assets or lack of remote operational functionality may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy.	Exhibit (PG&E-4), Chapter 4
8	Failure of Electric Distribution Underground Assets	The failure of distribution underground (including radial and network) assets or lack of remote operation functionality may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy.	Exhibit (PG&E-4), Chapter 5
9	Large Uncontrolled Water Release (Dam Failure)	Failure of a high or significant hazard dam, where failure or mis-operation could cause loss of human life and/or could cause economic loss, environmental damage, disruption of lifeline facilities, and other concerns.	Exhibit (PG&E-5), Chapter 1
10	Contractor Safety Incident	Any event resulting in a contractor serious injury or fatality as defined by PG&E's Serious Injury and Fatality (SIF) Standard which is aligned with the Edison Electric Institute (EEI) International Safety Classification and Learning (SCL) Model.	Exhibit (PG&E-7), Chapter 1
11	Cybersecurity Risk Event	A coordinated malicious attack targeting PG&E's core business functions, resulting in disruption or damage of systems used for gas, electric and/or business operations.	Exhibit (PG&E-7), Chapter 2
12	Employee Safety Incident	Any event resulting in: (1) a serious injury or fatality as defined by PG&E's SIF Standard which is aligned with the EEI SCL model or (2) a Days Away, Restricted, or Transferred incident as defined by the Occupational Safety and Health Administration.	Exhibit (PG&E-7), Chapter 3

FIGURE 1-1
SAFETY RISK RANK COMPARISON BETWEEN 2020 AND 2024 RAMP



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[1] *Risk event definitions/scope have changed since the 2020 RAMP.*
[2] *Wildfire risk score now also reflects consequences of Public Safety Power Shutoff (PSPS) and Enhanced Powerline Safety Settings (EPSS).*
[3] *For Public Contact, the scope was narrowed to focus on members of the public and third-party contractors experiencing serious injuries or fatalities resulting from interactions with intact energized electric facilities, not involving asset failure.*
[4] *Two risk models that were previously separate, Failure of Electric Distribution Network Assets and Failure of Electric Distribution Underground Assets, have been assembled into a single model.*

Leading up to filing this Report, PG&E conducted two public workshops to discuss PG&E's preliminary selection of risks to be included in this Report and to demonstrate its implementation of the Cost-Benefit Approach in accordance with the RDF Proceeding Phase II Decision. The workshops, and the feedback received from the Commission and parties, are discussed in Exhibit (PG&E-2), Chapters 2 and 4.

D. Risk-based Decision-making Framework in Context

This section places the RAMP risk mitigation strategies, as discussed in detail in the individual risk chapters, in the broader context of prudent utility management that includes all the factors that PG&E must consider and balance in planning for the future. PG&E is committed to implementing the Risk-Based Decision-Making Framework (RDF) that meets all the requirements of the RAMP process, and the proposed risk mitigation plans and cost estimates in this Report also must be understood in light of the following:

- Modeling limitations and uncertainties for rapidly evolving risk landscapes and risks with limited historic data that caution against relying too heavily on the current estimation of Risk Values and CBRs to prescribe future investment plans when a more flexible approach should be considered;
- Factors other than CBRs impacting selection of risk mitigation strategies; and
- The preliminary nature of the cost estimates presented for the selected mitigations and controls given that the final 2023 GRC decision was issued at the end of 2023 and the planning process for 2025-2030 is currently underway, likely resulting in GRC forecasts different from the proposed mitigations and cost estimates in this Report.

1. Risk-based Decision-Making Framework Limitations and Uncertainty

PG&E has made significant progress in developing and implementing the RDF as a key component of our planning process, and we also acknowledge that RDF is still not a singular tool for developing a comprehensive utility risk mitigation strategy. While the Commission and stakeholders continue to refine the framework in the Risk OIR, we must account for a number of existing gaps in important areas. These include: risk tolerance, i.e., how much safety, reliability, and financial risk is acceptable; uncertainties associated with emerging risks; risks with limited historical data; and risks rapidly evolving in nature, i.e., risks such as climate change and cyber attack. As the RDF framework matures we have confidence these areas will be addressed, but the current version is not designed to handle these issues definitively. These issues are discussed further below. Accordingly, CBR cannot be the sole factor informing the selection of mitigation strategies; we must consider other factors, including risk tolerance, compliance requirements, and modeling limitations and/or uncertainty. Modelling challenges related to individual risks are also discussed in the individual risk chapters of this report.

a. Risk Tolerance

A key area for continued development and maturity in the RDF is that of Risk Tolerance, i.e., how much risk is acceptable, or in other words, what it means to be “safe.” Guidance on risk tolerance is particularly important for risks that have low frequency but high safety consequence events. Under the current RDF, risk mitigation or risk control programs addressing a risk event with potentially serious safety consequences may have an estimated CBR of less than 1.0 simply because the frequency of the risk event is low. This is where Risk Tolerance is a necessary complement to Risk Value and CBR calculations, drawing a figurative line in the sand to say that potential serious injury or fatality incidents are unacceptable and the risk decisions are driven by intolerance of potentially serious safety consequences.

For example, in PG&E's current modeling, the "Locate and Mark – Distribution" Program that marks underground gas and electric facilities prior to excavation, has a modeled CBR of 0.5, i.e., significantly less than 1.0.[20] However, it is reasonable to believe that the Locate and Mark program has saved lives by preventing dig-ins leading to explosive loss of containment events. In the absence of a stated risk tolerance, stakeholders may argue that terminating the Locate and Mark program is in customers' best interest because it is not cost-effective. However, as discussed in Section D.1.c below, the low CBR is likely a reflection of a limitation with the quantification of program benefits with respect to accurately valuing long-standing but evolving risk control programs where there is no data to know how the risk would change if the control program was not present. Risk Tolerance guidance is needed to ensure that lifesaving programs like Locate and Mark will continue to be funded consistent with PG&E's standards, Commission directives, and legislation that places safe operations as the utility's top priority.

The Commission has recognized the need for discussion and clear guidance on Risk Tolerance and has expressed its intention to address this topic in future Phases of the Risk OIR. In the meantime, PG&E's risk mitigation strategies, as described in this report, are selected to ensure that safety remains PG&E's top priority.

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20 See Exhibit (PG&E-3), Ch. 2, "Loss of Containment Distribution Main or Service," Table 2-12.

b. Uncertainty and Future Risks

The CBA, as adopted in D.22-12-027, is not suited to modeling emerging risks that are highly uncertain, risk events for which there is little or no historic data to guide the analysis and inform investment in mitigations, and risks rapidly evolving in nature. The International Organization for Standards documents limitations of traditional cost-benefit analysis, including that it "requires a good understanding of likely benefits, so it does not suit a novel situation with high uncertainty" and:

> Depending on the discounting rate chosen, the practice of discounting to present values means that benefits gained in the long-term future can have negligible influence on the decision, so discouraging long-term investment.[21]

Two examples of these emerging and poorly understood risks are climate change and cybersecurity. With respect to climate change, while PG&E is certain assets will face increasing threat from natural hazards—both in the form of acute events such as flash flooding that can destroy utility facilities, or chronic exposure to high temperatures that shortens the operational life of assets—the timing of the most severe impacts is highly uncertain. Significant impact due to climate change may be on the order of decades in the future rather than years. PG&E discounts future benefits of mitigations, i.e., risk reduction, when computing CBRs. This is appropriate within the framework (as discussed in Exhibit (PG&E-2), Chapter 2), but discounting significantly diminishes the usefulness of the Cost Benefit Approach to evaluate climate-driven risk and potential mitigation options; the mitigations under consideration will likely not be deemed cost-effective (i.e., have a CBR above 1.0) when an investment is mitigating damage decades in the future.

In this report climate change is presented as a cross-cutting factor and its potential impacts are discussed in each risk chapter. The issue of how (or whether it is possible) to incorporate Climate Change

[21] Standards document IEC31010:2019, *Risk management – Risk assessment techniques*, p. 105.

modeling into the RDF is under consideration in Phase III of R.20-07-013.

In contrast to the uncertainty in climate change risk decades from now, the cybersecurity threat landscape is changing so rapidly that predicting the capabilities/methods of threat actors just months into the future is difficult. It is thus very difficult to assess risk three to seven years ahead, in alignment with the GRC cycle, or to describe the work that will be necessary to tackle emergent threats at that time. The only thing certain about significant cyber threats in the future is that they will not present exactly as they have in the past.

c. Uncertainty in Estimating Risk Reduction Benefits for Low Frequency/High Consequence Events

To estimate risk reduction benefits of proposed risk mitigations and controls, the current state of risk must be compared to either a future hypothetical state (for new mitigations) or a historic counterfactual state (for long standing controls). Uncertainty regarding the current, future hypothetical, and historic counterfactual states is especially high for low frequency/high consequence risk events because there is often little or no historic data to inform the risk assessments. For this reason, caution should be exercised in relying on modeled CBRs to inform the selection of mitigation and control programs that are addressing low frequency/high consequence events. For those programs, PG&E also considered other factors such as risk tolerance, compliance requirements and modeling limitations and/or uncertainties to inform its selection consistent with Commission guidance in D.22-12-027.

2. Factors Impacting Selection of Risk Mitigation Strategies

The Commission has acknowledged CBRs are not the only factors to consider in selecting mitigation strategies for RAMP risks. Use of CBRs to influence selection of risk mitigation strategies can and must be tempered by other factors. In D.22-12-027 the Commission expressly stated that [risk] mitigation selection can be influenced by other factors including, but not limited to, funding, labor resources, technology, planning and construction lead time, compliance requirements, risk tolerance thresholds, operational and execution considerations, and modeling limitations and/or uncertainties affecting the analysis.[22]

3. Framework for Developing Investment Plans and Cost Estimates

This Report includes risk reduction and cost-benefit analysis that is dependent upon programmatic cost estimates for the remaining years of the current rate case cycle (2025-2026) and for the upcoming GRC cycle, which covers the years 2027 (test year) through 2030 (attrition years). However, the mitigation plans and their cost estimates presented here are preliminary because they were mostly developed in late 2023 before the impact of the 2023 GRC decision was known or fully evaluated, and we are currently engaged in our investment planning process to generate the 2025-2030 outlook, which will inform the 2027 GRC filing.

Given that planning for 2025-2030 is underway and not complete, the cost estimates in this report are generally based on PG&E's 2024 budget plan carried forward through 2030. The 2024 budget was developed in 2023 before the final 2023 GRC decision was issued. We explain in this Report where specific cost estimates were not generally based on 2024 budgets but utilized some different methodology. Accordingly, the program funding and forecasts that we develop as a result of the 2025-2030 planning process, and present in the 2027 GRC application, will likely differ from the cost estimates presented in this Report.

The investment planning process leading up to the 2027 GRC forecast is informed by our ongoing strategic planning to identify investments and outcomes to deliver on our customers' rapidly growing energy needs while overcoming challenges faced in many areas, including affordability, risk, and safety (known as our True North Strategy).

To achieve these strategic objectives, while also delivering affordable energy to our customers, PG&E is improving its foundational capabilities, including development of our PG&E Performance Playbook which includes both the enterprise Lean Operating System and a PG&E Safety Excellence Management System; overhaul of our Information Technology and data

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[22] D.22-12-027, Appendix A, p. A-16, No. 26.

functionality and work planning capabilities; and implementation of a regional service model.

One of the key initiatives to implement our overall strategy is an enhanced data-driven approach in Electric Operations to optimize the investment plan to efficiently address multi-dimensional needs such as risk reduction and capacity (known as the Integrated Grid Planning (IGP) initiative). IGP is a multistep process that enables implementation of asset and portfolio management tools to bundle and optimize work through a value framework. This value framework model incorporates total asset needs including risk (e.g., wildfire risk, overloading, poor asset health, poor reliability); cost; budgetary constraints; prioritization; and regulatory commitments. Through incorporating all these variables, PG&E will be better able to maximize risk reduction while simultaneously reducing the total cost to complete the required work.

E. Lessons Learned and Future Enhancements

As discussed above and throughout this Report, PG&E's experience in participating with the Commission and other stakeholders in the further development of the RDF, and in performing the analysis presented in this Report, has helped us identify key learnings and take-aways that we believe should guide the future path of the RDF. The goal of the RDF is to allow the Commission to evaluate the IOU's proposed safety investments in the GRC to ensure the adoption of a risk-informed portfolio of programs that drives down safety risk for PG&E workers and the public, and is affordable for customers. In the spirit of this endeavor, we offer the following lessons learned for consideration by the Commission:

- Risk assessments and mitigation strategies must remain flexible in the face of a dynamic and evolving risk landscape;
- Modeling limitations and uncertainties caution against relying too heavily on the current estimation of Risk Values and cost benefit ratios to prescribe future investment plans when a more flexible approach should be considered;
- Risk mitigation planning decisions should be informed by both quantitative models and other factors that must be weighed and balanced in planning for

the future, including factors that are either not addressed or not captured adequately in RAMP's quantitative models;

- Further guidance on risk tolerance is needed to inform mitigation strategy risk reduction for programs that are not cost-effective under the quantitative risk modelling; and
- Safety must remain the top priority, even though electric reliability has become a significantly larger contributor to the risk values than in the past. It is therefore crucial that the RDF be further developed to incorporate appropriate safety-focused risk tolerance policies and guidelines.

PG&E's 2024 RAMP Report represents a significant milestone in advancing utility Risk-Informed Decision making in California, and we know that much work remains ahead. Together we must address the need for a flexible balanced approach; quantitative modelling uncertainties and limitations; and risk tolerance guidelines. In addition, PG&E's ESJ pilot study included in this Report represents an initial attempt to address potential ESJ equity issues in risk and mitigations, and is intended to identify the complexities involved and possible approaches. Similarly, in Phase III of the Risk OIR, PG&E proposed how Climate Change can be incorporated into the RDF and has suggested that our proposal be piloted based on data and analysis from this RAMP filing. PG&E looks forward to continued participation in the Risk OIR to address these and other important issues.

PG&E is committed to continuing to work with the Commission and other parties to refine and enhance the risk-based decision-making framework to address the issues discussed above and in this Report.

F. Organization of this Report

The remainder of this Report is organized as follows:

TABLE 1-2
SUBSEQUENT RAMP REPORT CHAPTERS

Line No.	RAMP Exhibit	Chapter	Contents
1	2	1	Risk Management Framework
2	2	2	Risk Modeling and Cost-Benefit Ratio
3	2	3	Cross-Cutting Factors
4	2	4	RAMP Risk Selection
5	2	5	Safety Culture, Policy, and Compensation
6	2	6	Climate Resilience
7	2	7	Environmental and Social Justice Pilot Study Implementation
8	3	1-3	Gas Operations RAMP Risks
9	4	1-5	Electric Operations RAMP Risks
10	5	1	Energy Supply RAMP Risks
11	7	1-3	Enterprise Health and Safety, Information Technology, and Shared Services RAMP Risks
12	8	Appendix A	Environmental and Social Justice Pilot Study Plan
13	8	Appendix B	Risk Modeling Acronyms

This RAMP Report includes a separate chapter for each of the 12 RAMP risks presented in Table 1-1 above. Each risk is presented in a standard format with the same elements. Each chapter ends with an alternative mitigations analysis showing the proposed mitigation plan and two or more alternative plans.

G. Conclusion

The 2024 RAMP report is PG&E's third RAMP filing. It advances PG&E's efforts over the last decade to continuously improve the management of its safety risks. The Report demonstrates progress in our understanding, analysis, quantification, and mitigation of risk.

PG&E acknowledges and appreciates the significant contributions from SPD and other CPUC staff and parties at the workshops, and throughout the decade-long journey to improve the methodology employed for systematic and quantitative risk assessment and mitigation. This Report incorporates feedback from the Commission and other stakeholders in a variety of forums since PG&E's 2020 RAMP Report.

Application: 24-05-
(U 39 G)
Exhibit No.: (PG&E-2)
Date: May 15, 2024
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT

EXHIBIT (PG&E-2)

RISK MANAGEMENT, SAFETY, AND PLANNING

PACIFIC GAS AND ELECTRIC COMPANY
2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
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RISK MANAGEMENT, SAFETY, AND PLANNING

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PACIFIC GAS AND ELECTRIC COMPANY RISK ASSESSMENT AND MITIGATION PHASE CHAPTER 1 PG&E'S ENTERPRISE RISK MANAGEMENT FRAMEWORK

A. Introduction

Pacific Gas and Electric Company's (PG&E or the Company) Enterprise and Operational Risk Management (EORM) Department has centrally governed the Company's processes for identifying, assessing, mitigating, and monitoring risk (namely, Enterprise Risk Management (ERM)) since its inception in 2012. PG&E's approach for ERM has evolved since that time because of lessons learned, feedback from external stakeholders, benchmarking, and risk management best practices. This chapter provides an overview of the current state of the ERM program, including:

- PG&E's ERM Framework; and
- Changes since PG&E's 2020 Risk Assessment and Mitigation Phase (RAMP) Report.

B. PG&E's ERM Framework

1. Objective of PG&E's ERM Program

The objective of PG&E's ERM program is to facilitate risk-based, data-driven decision-making that results in measurable risk reduction. PG&E's ERM processes are based on the principles of the widely-used International Organization for Standardization (ISO) 31000[1] Risk Management standard and help the Company to systematically identify, evaluate, prioritize, mitigate, and monitor risks inherent in its operations.

EORM provides central coordination of risk management, analysis, and execution. Through application of the ERM framework and continual improvements, PG&E comprehensively identifies risks that could lead to significant consequences at an enterprise level, and then provides risk

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[1] ISO 31000 is a family of standards relating to risk management codified by the ISO. The purpose of ISO 31000 is to provide principles and generic guidelines on risk management. ISO 31000 seeks to provide a universally recognized paradigm for practitioners and companies employing risk management processes.

metrics for comparing and prioritizing actions that have the best potential to reduce risk.

2. Implementation of ERM

The ERM program is an integral part of how PG&E provides safe and reliable utility service. EORM provides governance for PG&E's ERM program and supports the Functional Areas (FAs, previously, Lines of Business, or LOB), who are responsible for identifying, evaluating, mitigating, and monitoring the risks. The Chief Risk Officer (CRO) approves the addition/deletion of risks to/from the Corporate Risk Register (CRR). EORM manages and maintains the CRR and provides oversight by monitoring and validating the status of the Company's risk mitigation activities.

EORM also works with FAs to:

- Identify and evaluate risks using a blend of qualitative and quantitative techniques;
- Develop risk response plans based on an analysis of reasonable alternative mitigation strategies;
- Establish metrics to monitor risks and measure the effectiveness of mitigations;
- Provide oversight to ensure the FAs follow the standards and procedures established and maintained by EORM;
- Advocate for PG&E in, and implement the outcomes of regulatory risk proceedings such as the Risk-Based Decision-Making Framework (RDF) Order Instituting Rulemaking[2] and Safety Model Assessment Proceeding (S-MAP);[3]
- Facilitate cross-functional risk meetings to promote consistency, continuous improvement, and sharing of best practices;
- Report to senior management on the status of risk management at PG&E, including whether the FAs have dedicated and qualified resources to manage risks on the CRR consistent with their mitigation strategies;

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[2] R.20-07-013.

[3] A.15-05-002.

- Support risk-informed decision-making in PG&E's planning processes; and
- Manage a database to store the Company's ERM process records.

3. Organization Structure

PG&E's risk governance structure is led by the CRO and Senior Vice President (VP), Ethics and Compliance, who, effective August 2, 2023, reports to the Executive VP of General Counsel and Chief Ethics and Compliance Officer. The CRO also reports to the Safety and Nuclear Oversight (SNO) Committees and Audit Committees of the Board of Directors. The CRO is the enterprise risk officer for PG&E with oversight of risk assessment and mitigation. The CRO has oversight of risks associated with PG&E's operations and the environment related to public safety. This includes, but is not limited to, nuclear risk, wildfire risk, and risks of other natural disasters as well as new strategic risks confronting utilities such as business interruption from cyber-attack, storms, and other catastrophic events.

EORM consists of three groups reporting to the VP, Enterprise and Operational Risk Management, who reports to the CRO. These groups are: (1) EORM; (2) Operational Risk Validation (ORV); and (3) Compliance and Operational Assurance (COA). The EORM group is responsible for implementation, strategy and analytics associated with the ERM program. The ORV group is responsible for assessing and validating risk mitigations and controls to determine the effectiveness of PG&E's programs to reduce risk and drive program improvements. The COA group is responsible for validating commitment development and execution to ensure compliance with PG&E's Wildfire Mitigation Plan.

4. Governance

EORM's role has increased within the Company to reflect PG&E's heightened focus on reducing risk in our operations. Our focus on risk is reflected at every level of the Company, from the Board of Directors to individual contributors. EORM conducts "horizon scanning" in multiple forums at different levels of the organization. Forums where risk is evaluated, discussed, and monitored throughout the Company include:

- Board Committees: Four Board of Director-level committees (Audit, Finance, Sustainability & Governance, and SNO) provide oversight of Enterprise Risks and associated mitigation activities. Board Committees receive updates on the risk management program, approve the designation of Enterprise Risks[4] and Enterprise Cross-Cutting Factors[5] and provide oversight to these Enterprise Risks and Enterprise Cross-Cutting Factors at least every 12 months.
- Enterprise Risk Command Center (ERCC): The ERCC, chaired by the CRO and comprised of the CEO, Executive VPs, and risk owners, meets monthly to monitor the effectiveness of controls and mitigations in ensuring risk reduction activities meet objectives, escalate, and resolve cross-functional risk issues, and monitor emerging risks. The ERCC also oversees risk management program strategy and performs deep dives and challenge sessions into specific top risks.
- Risk Management Community (RMC) Meetings: RMC meetings are held monthly, where EORM leads a discussion with Risk Managers from all FAs, Compliance Liaisons, and other interested parties on various risk management topics. The RMC is the forum used to present risk program updates, share best practices, discuss challenges, and encourage employees to speak up and raise issues as needed.
- FA Risk and Compliance Committees (RCC): Each FA conducts RCC meetings chaired by the most senior Officer in the FA, or equivalent forums per internal standards, to provide oversight for risk and compliance performance and initiatives for which they have ownership, raise and resolve issues, and share best practices. These take place throughout the year, at least quarterly, though most are monthly. Each FA RCC oversees the actions taken to actively manage the operational and strategic risks inherent to that FA. If a pertinent issue is raised that requires further investigation, an owner is designated with the

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4 "Enterprise Risks" are risks identified through the EORM Program as potentially catastrophic and recommended by senior management for Board-level review.

5 "Enterprise Cross-Cutting Factors" is the term used to describe cross-cutting risk drivers or controls associated with one or more Enterprise Risks that are recommended for Board-level review.

understanding that the item will be tracked and brought to the appropriate FA's RCC for further review and resolution.

With these forums, EORM works closely with Risk Owners and Risk Managers in each FA.

Risk Owners are assigned to each CRR-risk. Risk Owners are responsible for the strategies, activities, and functions that relate to managing the risk. They identify a support system within their organizations composed of subject matter experts, data management and modeling resources, mitigation and control owners, and others necessary to ensure all risk management functions are completed.

Risk Managers in each FA manage all risk-related activities within that FA, which includes risk assessments and quantification, reporting and governance, and tracking metrics and mitigations. EORM provides support to FA Risk Managers by embedding risk professionals in key areas to ensure: (1) the data, models, assumptions and calculations used for decision-making have integrity; (2) there are feedback loops to assess the risk reducing impact of executed work; (3) the level of risk reduction achieved through compliance driven processes and controls is understood; and (4) that there is "line of sight" from the top risks to executed work.

In addition to the governance structure and forums described above, there are additional tools we use to monitor and evaluate risk:

- Guidance documents outline the ERM process including roles and responsibilities for governance, oversight, execution, and support.
- The Corrective Action Program (CAP) enables employees and contractors to identify and track equipment and safety issues, ineffective and inefficient work processes and procedures, and provide suggestions on how to execute work more safely or efficiently. All employees and contractors with access to PG&E's computer network can enter an issue into the CAP system via the intranet and mobile devices, phone, and paper. A similar system has been in place for decades at the Diablo Canyon Power Plant and has been instrumental in supporting a speak-up culture.

C. Key Improvements Since PG&E's 2020 RAMP

1. Cost-Benefit Approach Methodology

Pursuant to the RDF Proceeding Phase II Decision,[6] PG&E constructed a Cost-Benefit Approach (CBA) and implemented in 2023 the methodology for risk and mitigation analysis to be consistent with the Decision. A description of how PG&E implemented this methodology is in Exhibit (PG&E-2), Chapter 2.

2. Risk Model Updates

Since the second-generation RAMP risk models introduced in the 2020 RAMP, PG&E has enhanced the capability of its models and made changes to ensure compliance with the Phase I[7] and II Decisions of the RDF Proceeding. The key update to the current models is the conversion to the CBA for risk measure and transition from Risk Spend Efficiency (RSE) to Cost Benefit Ratio (CBR) calculations for mitigation analysis.

Detailed information about PG&E's risk models and associated updates are in Exhibit (PG&E-2), Chapter 2.

3. Changes to the Risk Register Affecting RAMP

There have been minor changes to PG&E's CRR since the 2020 RAMP as follows:

- Cybersecurity Risk Event as an event-based risk was created with a corresponding reduction in the scope of the Cybersecurity cross-cutting factor;
- Wildfire risk modeling has subsumed the impact of PSPS and EPSS;
- Public Contact with Intact Energized Electrical Equipment (previously Third-Party Safety Incident) has been redefined with a narrower scope to focus on members of the public and third-party contractors experiencing serious injuries or fatalities resulting from interactions with intact energized electrical facilities;

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6 D.22-12-027.

7 D.21-11-009.

- Failure of Electric Distribution Underground Assets has combined Failure of Electric Distribution Network Assets and Failure of Electric Distribution Underground Assets into a single risk and model;
- Access Asset Incident Risk was added after identification during horizon scanning and assessment;
- Failure of Electric Substation Asset risk was split into transmission and substation risks with each modeled independently.

Exhibit (PG&E-2), Chapter 4 provides information about PG&E's selection of RAMP Risks and expands upon PG&E's Risk Register.

4. Commitments Following the 2020 RAMP Report

In PG&E's 2023 General Rate Case (GRC), PG&E provided next steps to improve its Risk Management Program. PG&E reports on the progress of these next steps below:

- 2020 Critical Issue 1 Resolution: Safety Policy Division (SPD) found that the 2020 RAMP report lacked granularity in the assignment of tranches. PG&E addressed this issue by significantly enhancing the granularity of the tranches of its risk models, for instance the Loss of Containment on Gas Distribution Main or Service risk expanded from 12 tranches to 34 in the 2023 GRC and to 42 tranches in this RAMP, and Wildfire risk expanded from eight tranches to 40 in the 2023 GRC and to 50 tranches in this RAMP. In this RAMP, PG&E has continued to improve its tranching methodology for many risks to ensure compliance with the RDF Proceeding Phase II Decision,[8] better align with operational and planning models, logically aggregate assets, and homogenize risk scores.
- 2020 Critical Issue 2 Resolution: SPD found that RSEs were not provided for controls. PG&E addressed this issue in the 2023 GRC by providing RSEs in controls. In this RAMP report, PG&E has provided Cost-Benefit Ratios (CBR) for Controls.

PG&E reviewed the 2023 GRC Decision and did not identify any issues addressing its risk management process or models.

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8 D.22-12-027, Appendix A, p. A-13, No. 14.

PACIFIC GAS AND ELECTRIC COMPANY
RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 2
RISK MODELING AND COST-BENEFIT RATIO

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RISK MODELING AND COST-BENEFIT RATIO

A. Introduction

This chapter provides a detailed discussion of the Cost-Benefit Approach (CBA), Risk Value,[1] and Cost-Benefit Ratio (CBR) methodology used to quantitatively assess risks and mitigations throughout this report. It also includes numerical examples to illustrate how these methods are applied.

The Order Instituting Rulemaking to Further Develop a Risk-Based Decision-Making Framework for Electric and Gas Utilities Proceeding (RDF Proceeding) Phase II Decision[2] modifies the Risk-Based Decision-Making Framework (RDF) adopted in Decision (D.) 18-12-014,[3] the Phase Two Decision Adopting Safety Model Assessment Proceeding Settlement Agreement Modifications (SA Decision, and also referred to as the S-MAP Settlement Agreement). It replaces the "Multi-Attribute Value Function" adopted in the SA Decision with a Cost-Benefit Approach that includes standardized dollar valuations of Safety, Electric Reliability and Gas Reliability Consequences from Risk Events. The Commission directs the large Utilities to implement the following steps to analyze risk and mitigation choices in Appendix A of the RDF Proceeding Phase II Decision:

- Building a Cost-Benefit Approach – Step 1A;
- Identifying Risks for the Enterprise Risk Register[4] – Step 1B;
- Risk Assessment and Risk Ranking in Preparation for Risk Assessment and Mitigation Phase (RAMP) – Step 2A;
- Selecting Enterprise Risks for RAMP – Step 2B; and

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1 PG&E uses the term "Risk Value" and "Risk Score" interchangeably throughout this report.

2 D.22-12-027, Phase Two Decision Adopting Modifications to the RDF Adopted in D.18-12-014 and Directing Environmental and Social Justice (ESJ) Pilots.

3 D.18-12-014, Phase Two Decision Adopting Safety Model Assessment Proceeding Settlement Agreement with Modifications.

4 PG&E uses the term Corporate Risk Register (CRR) instead of Enterprise Risk Register.

- Mitigation Analysis for Risks in RAMP – Step 3.[5]

Each of the Steps, and the associated Rows are described in detail in Appendix A to the RDF Proceeding Phase II Decision.

This chapter describes Steps 1A and 3. Steps 1B, 2A, and 2B are described in Exhibit (PG&E-2), Chapter 4.

The terms used to describe the different elements of Pacific Gas and Electric Company's (PG&E or the Company) risk model and risk analysis efforts are based on the definitions provided in the RDF Proceeding Phase II Decision.[6] Terms that are not defined in the RDF Proceeding Phase II Decision are defined in this Chapter the first time they are used.

B. Risk Management Approach

PG&E's risk modeling, analysis and mitigation strategy is focused on reducing the potential for catastrophic risk events and the consequences of those events. In terms of risk modeling, this strategy entails paying special attention to tail risk—the low frequency, high consequence events. We achieve this in the 2024 RAMP by using a risk-averse Risk Attitude Function (also known as a Risk Scaling Function) which gives a greater weight in the risk model to low frequency, high consequence events than to high frequency, low consequence events.[7] PG&E's approach of using a risk-averse Risk Attitude Function more appropriately values risks with extreme outcomes compared to using a risk-neutral function, but ultimately, the determination of what level of risk is acceptable, i.e., Risk Tolerance, is a crucial, missing piece in the RDF that will ultimately need to be addressed by the Commission.

PG&E is risk-averse in the economic sense of that term. Given a choice between two mitigations that theoretically reduce the same expected amount of loss, one of which is targeted at catastrophic (low frequency, high consequence) risk events and another that is targeted at routine (high frequency, low consequence) risk events, it prefers to choose the mitigation that targets the catastrophic events because of the uncertainty of their exact frequency and

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5 D.22-12-027, Appendix A, p. A-6.

6 D.22-12-027, Appendix A, pp. A-3 to A-5.

7 PG&E's use of a non-linear Risk Attitude function is described in Section C.6, below.

consequence, and the failure to account for complete loss, the risk or ruin.[8] Catastrophic events can have a more severe impact than multiple routine events for numerous reasons, including:

- The maximum scope and consequences of certain catastrophic events, such as a wildfire, are very hard to determine;
- Catastrophic events can overwhelm emergency facilities and infrastructure; and
- Catastrophic events can have significant, unforeseen consequences that are not factored into everyday operations and contingency planning, and therefore have a greater potential to disrupt PG&E's operations (compared to multiple low consequence events).

We have learned through experience that the biggest risk events—those that disrupt the lives and wellbeing of our customers, their communities, and PG&E itself—are the ones that should be prioritized to avoid. Therefore, by clearly understanding what drives these risk events, and then implementing the right programs to prevent them in the future.

C. Cost-Benefit Approach

Step 1A in the RDF Proceeding Phase II Decision requires utilities to build a CBA to evaluate and rank alternative risk mitigation programs.[9] PG&E's CBA reflects focus on appropriately valuing low-frequency/high-consequence risk events without neglecting operational risks (high-probability/low-consequence events).

Appendix A (of the RDF) lists the six principles according to which the CBA should be constructed.[10] The six principles are shown in rows 2 through 7 in Table 2-1 below.

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8 R.20-07-013, PG&E Opening Comments on Workshop #4 (Nov. 6, 2023), pp. 3-6, Risk Scaling.

9 D.22-12-027, Appendix A, p. A-7, No. 1.

10 D.22-12-027, Appendix A, pp. A-7 to A-8, Nos. 2-7.

TABLE 2-1
STEP 1A – BUILDING A COST-BENEFIT APPROACH

Row No.	Element Name	Element Description and Requirements
1	CBA	A utility's CBA should be constructed by following these six principles (see Rows 2-7, below). The CBA is required to be built once, but the utility may adjust its CBA over time. Any changes to the CBA must adhere to the principles of construction set forth in Rows 2 through 7 below.
2	CBA Principle 1 – Attribute Hierarchy	Attributes are combined in a hierarchy, such that the primary Attributes are typically labels or categories and the sub-Attributes are observable and measurable.
3	CBA Principle 2 – Measured Observations	Each sub-Attribute has Levels expressed in natural units that are observable during ordinary operations and as a consequence of the occurrence of a Risk Event.
4	CBA Principle 3 – Comparison	Use a measurable proxy for an Attribute that is logically necessary but not directly measurable. This principle only applies when a necessary Attribute is not directly measurable. For example, a measure of the number of complaints about service received can be used as a proxy for customer satisfaction.
5	CBA Principle 4 – Risk Assessment	When Attribute Levels that result from the occurrence of a Risk Event are uncertain, assess the uncertainty in the Attribute Levels by using expected value or percentiles, or by specifying well-defined probability distributions, from which expected values and tail values can be determined. Monte Carlo simulations or other similar simulations (including calibrated subject expertise modeling), among other tools, may be used to satisfy this principle.
6	CBA Principle 5 – Monetized Levels of Attributes	Apply a monetized value to the Levels of each of the Attributes using a standard set of parameters or formulas, from other government agencies or industry sources, as determined by the *Phase II Decision Adopting Modifications to the Risk-Based Decision-Making Framework Adopted in D.18-12-014 and Directing Environmental and Social Justice Pilots* in Rulemaking (R.) 20-07-013. A utility may deviate from the agreed upon standard set of parameters or formulas by submitting a detailed explanation as to why the use of a different value would be more appropriate. The use of a different set of parameters or formulas to determine the Monetized Levels of Attributes requires an analysis comparing the results of its "equivalent or better" set of parameters or formulas against the results of the agreed upon standard set of parameters or formulas.
7	CBA Principle 6 – Risk-Adjusted Levels	Apply a Risk Attitude Function to the Monetized Levels of an Attribute or Attributes (from Row 6) to obtain Risk-Adjusted Levels. The Risk Attitude Function specifies attitude towards different kinds of Outcomes including capturing aversion to extreme Outcomes or indifference over a range of Outcomes. The Risk Attitude Function can be linear or non-linear. For example, the Risk Attitude Function is linear to express a risk-neutral attitude if avoiding a given change in the Monetized Attribute Level does not depend on the Attribute Level. Alternatively, the Risk Attitude Function is non-linear to express a risk-averse or risk-seeking attitude if avoiding a given change in the Monetized Attribute Level differs by the Attribute Level.

1. Implementing CBA Principle 1 – Attribute Hierarchy

Principle 1 requires that Utilities identify Attributes that are combined in a hierarchy such that the primary Attributes are categories and the sub-Attributes, are observable and measurable.[11]

PG&E identified three Attributes: (1) Safety, (2) Reliability, and (3) Financial.

1) "Safety" has two observable and measurable sub-Attributes: Direct and Indirect consequences. A Direct Safety consequence occurs when a Risk Event is established as the predominant reason for said consequence. For this RAMP, PG&E is incorporating Reliability-induced Indirect Safety consequences in its modeling as well. These consequences represent instances where loss of electric or gas service from a Risk Event could result in injuries or fatalities, for example, with customers that constantly rely on medical equipment for their well-being. In D.14-12-025, the Commission recognized " that reliability-related issues can affect safety. In such situations, those reliability issues should be included in the assessment of safety."[12] Furthermore, in PG&E's Test Year 2023 GRC Application (A.20-06-012), the Commission ruled that it was appropriate for PG&E to provide testimony estimating the safety consequences of PSPS events (an event that heretofore was modeled to have only Reliability and Financial consequences).
2) "Reliability" has two observable and measurable sub-Attributes: Electric Reliability, representing the degree and extent to which customers are impacted by interruption of electric service due to a Risk Event; and Gas Reliability, to capture the impact of gas service interruptions due to a Risk Event.
3) "Financial" represents any monetary consequences impacting customers due to a Risk Event. Pursuant to D.18-12-014 and D.16-08-018, shareholders' financial interests are excluded.[13]

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[11] D.22-12-027, Appendix A, p. A-7, No. 2.

[12] D.14-12-025, p. 20.

[13] D.18-12-014, p. 29, and D.16-08-018, p. 193, Conclusion of Law 37.

2. Implementing CBA Principle 2 – Measured Observations

CBA Principle 2 requires that each sub-Attribute have its own Levels expressed in natural units that are observable during ordinary operations and as a Consequence of a Risk Event (CoRE).[14]

a. Direct and Indirect Safety – Equivalent Fatalities (EFs)

EFs are defined as the sum of Fatalities and Serious Injury Equivalents per event occurrence. Serious Injury is defined as an injury that requires in-patient hospitalization of an individual pursuant to existing Federal and State reporting guidelines.[15,16] The RDF Proceeding Phase II Decision requires each investor-owned utility (IOU) to apply one of two methods for the valuation of injury prevention, expressed as a fraction of a fatality, depending on the availability of data:[17]

- Define a serious injury as 0.25 of a fatality; or
- Apply the Maximum Abbreviated Injury Scale (MAIS) based injury severity level adopted by the U.S. Department of Transportation (DOT) for the value of injury prevention.[18]

PG&E is applying the second method in this RAMP Report for select risks where safety incident data are available at a more granular level. This represents an advancement from PG&Es 2020 RAMP Report. Fatalities and varying degrees of injury are converted to EFs using the factors shown in Table 2-2. For risk events where injury data beyond Serious Injury or Fatality are not available, PG&E uses the same conversion rate from Serious Injury to EF as previously; a serious injury is equivalent to 0.25 of a fatality, consistent with the first method defined above.

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14 D.22-12-027, Appendix A, p. A-7, No. 3.

15 49 CFR § 191.3, Definitions: Incident. See also: <https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-facility-incident-report-criteria-history> (accessed May 2, 2024).

16 D.06-04-055, Appendix B, Accident Report Requirements, p. 2, No. 3.

17 D.22-12-027, p. 64, Ordering Paragraph (OP) 2(a)(ii).

18 DOT VSL Guidance – 2021 Update, p. 10, available at: <https://www.transportation.gov/resources/value-of-a-statistical-life-guidance> (accessed May 2, 2024).

TABLE 2-2
EQUIVALENT FATALITY CONVERSION FACTORS
SIMULATED FATALITY OR SERIOUS INJURY QUANTITIES

Line No.	MAIS Level	Injury Severity	Fraction of Fatality	
1	MAIS 1	Minor	0.003	0.003
2	MAIS 2	Moderate	0.047	0.253
3	MAIS 3	Serious	0.105	
4	MAIS 4	Severe	0.266	
5	MAIS 5	Critical	0.593	
6	MAIS 6	Unsurvivable	1.000	1.000

1) Indirect Safety Sub-Attribute

In addition to quantifying the standard dollar valuation of electric reliability risk, for electric outages with a duration of greater than eight hours, PG&E considers this to be a medically-relevant outage duration with potential adverse health consequences.[19] In order to estimate the relationship between safety consequences and extent of electric outage, PG&E has reviewed literature on the widespread U.S. blackout event for reported or estimated outage-related mortality and the extent of the outages during such events. The data sources represent a wide array of events with many varied drivers of injuries and fatalities other than the electric power outages, indicating a wide uncertainty in this. While acknowledging the high uncertainty inherent and a wide array of factors and unique situations that impact the indirect safety impact from power outages, PG&E included potential indirect safety impacts by partially representing the uncertainty using the exponential probability distribution with the mean of six EFs per Billion Customer Minutes Interrupted (CMI; see below) for events of eight hours of duration or greater, where the mean was obtained based on mean of the ratio of estimated or reported outage-related fatality to CMI from six

[19] Do, et al., also considers eight-hours of duration as medically-relevant outages in their research: Vivian Do, et al., Nature Communications, Spatiotemporal distribution of power outages with climate events and social vulnerability in the USA (Apr. 29, 2023), available at: https://doi.org/10.1038/s41467-023-38084-6 (accessed May 7, 2024).

widespread blackout events.[20],[21] The indirect safety consequence is included in addition to any direct safety consequences into the Safety Risk Values modeled for event-based risks with an Electric Reliability Attribute.

b. Electric Reliability – CMI

Electric Reliability is measured by Customer Minutes Interrupted (CMI), defined as the number of minutes of forced outage duration multiplied by the number of customers impacted given the occurrence of a Risk Event.

c. Gas Reliability – Number of Customers Impacted

Gas Reliability is measured by the Number of Customers impacted by an unplanned interruption of gas service due to a Risk Event.

d. Financial – Dollars

Financial Consequences are measured for all future years in 2023 real dollars.

3. Implementing CBA Principle 3 – Comparison

CBA Principle 3 directs Utilities to use a measurable proxy for any Attribute that is logically necessary, but not directly measurable.[22] Since all PG&E's Attributes are directly measurable, proxies are not used.

4. Implementing CBA Principle 4 – Risk Assessment

CBA Principle 4 states that when Attribute levels resulting from the occurrence of a Risk Event are uncertain, the utility should assess the uncertainty in the Attribute Levels using expected values or percentiles, or by specifying well-defined probability distributions from which expected

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[20] These six events are 2023 U.S. Northeast Blackout, 2011 Southwest Blackout, 2012 superstorm Sandy, 2012 Derecho Windstorms, 2017 Hurricane Irma, and 2021 Texas Blackout.

[21] PG&E notes that the indirect safety estimates are still uncertain even if being represented by a probability distribution because, among other things, the mean itself is uncertain (only six events had reported or estimated outage-related mortality in the literature), the true probability distribution might not be exponential distribution, and there are missing factors (e.g., natural hazards and related damage, emergency preparedness and response, proportion of vulnerable population, etc.) that influence the indirect safety consequences but the research or data is not readily available.

[22] D.22-12-027, Appendix A, p. A-7, No. 4.

values and tail values can be determined. Monte Carlo simulations may be used to satisfy this principle.[23]

PG&E employs a probabilistic approach to modeling Attribute Levels. The Attributes are specified by well-defined conditional probability distributions with parameters derived from data and/or calibrated subject matter expert (SME) input. Monte Carlo methods are used to simulate Attribute Levels from these distributions. Details about PG&E's Risk Assessment methodology and a numerical example are presented in Section D.

5. Implementing CBA Principle 5 – Monetized Levels of Attributes

CBA Principle 5 requires Utilities to apply a monetized value to the Levels of each of the Attributes using a standard set of parameters or formulas, from other government agencies or industry sources, as determined by the RDF Proceeding Phase II Decision.[24]

a. Safety Attribute

The RDF Proceeding Phase II Decision requires each IOU to express the Safety Attribute using one of two methods:

1) Apply the most current published DOT VSL, adjusted for the base year of their respective RAMP filing.[25]
2) Use an alternative VSL within the high and low ranges provided by the United States Department of Health and Human Services (HHS) and provide a sensitivity analysis for the CBR impact of its choice compared to the standard DOT VSL.[26]

The DOT VSL estimate relies on national average price and earnings data. PG&E's risk assessments are conducted considering rate payers in California, where income and inflation trends are higher

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23 D.22-12-027, Appendix A, p. A-7, No. 5.

24 D.22-12-027, pp. 63-65, OP 2.

25 DOT VSL Guidance – 2021 Update, available at: <https://www.transportation.gov/resources/value-of-a-statistical-life-guidance> (accessed May 2, 2024).

26 See HHS, Updating Value per Statistical Life Estimates for Inflation and Changes in Real Income (Apr. 2021), available at: <https://aspe.hhs.gov/sites/default/files/2021-07/hhs-guidelines-appendix-d-vsl-update.pdf> (accessed May 2, 2024).

than the national average. As a result, there is justification that California IOUs should use a California-adjusted VSL.[27] Therefore, PG&E is using a California-adjusted DOT VSL calculation with California price index and income multipliers from public data sources.

DOT VSL

The DOT updates the VSL annually based on changes to income and inflation using the following formula:

$$VSL_t = VSL_0 \times \left(\frac{P_t}{P_0}\right) \times \left(\frac{I_t}{I_0}\right)^{\varepsilon}$$

Using the DOT VSL formula, PG&E calculated a value of $13.2 million in $2023. Table 2-3 shows values and data sources for each of the DOT VSL formula elements that were included in the calculation, consistent with the DOT VSL Guidance.

TABLE 2-3
DOT VSL CALCULATION DETAILS

Line No.	Element	Value	Data Source
1	*0* = Original Base Year	2012	
2	*t* = Current Base Year	2023	
3	P_0 = Price Index in Original Base Year	229.594	BLS Consumer Price Index for All Urban Consumers (CPI-U)[a]
4	P_t = Price Index in Current Base Year	304.702	
5	I_0 = Real Incomes in Original Base Year	335	Median Usual Weekly Earnings (MUWE), in constant (1982-84) dollars, derived by BLS from the Current Population Survey[b]
6	I_t = Real Incomes in Current Base Year	367	
7	$\mathcal{E}$ = Income Elasticity of VSL	1	DOT VSL Guidance – 2021 Update[c]
8	VSL_0 = VSL in Original Base Year	$9.1 million	
9	VSL_t = VSL in Current Base Year	$13.2 million	

(a) BLS Series CUUR0000SA0. Available at: https://data.bls.gov/timeseries/CUUR0000SA0.
(b) BLS Series LEU0252881600. Available at: https://data.bls.gov/timeseries/LEU0252881600.
(c) DOT VSL Guidance – 2021 Update at 7. Available at: https://www.transportation.gov/resources/value-of-a-statistical-life-guidance.

27 For example, see Zan, H., Scharff, R.L. *Regional Differences in the Value of Statistical Life*. J Consum Policy 40, 157–176 (2017).

California-Adjusted DOT VSL

PG&E applied California income and price multipliers that increase the DOT VSL value from $13.2 million to $15.2 million in $2023. The California adjusted DOT VSL formula is:

$$VSL_{t,CA} = VSL_t \times \left(\frac{P_{t,CA}}{P_t}\right) \times \left(\frac{I_{t,CA}}{I_t}\right)$$

Table 2-4 shows values and data sources for each of the California-adjusted DOT VSL formula elements that are included in the calculation.[28]

TABLE 2-4
CALIFORNIA-ADJUSTED DOT VSL CALCULATION DETAILS

Line No.	Element	Value	Data Source
1	$P_{t,CA}$ = Price Index in Year t, California	331.804	Consumer Price Index for All Urban Consumers - California (CPI-U)[(a)]
2	P_t = Price Index in Year t	304.702	BLS Consumer Price Index for All Urban Consumers (CPI-U), used in the DOT VSL[(b)]
3	$I_{t,CA}$ = Real Incomes in Year t, California	388	Median weekly earnings, Full-time wage and salary workers, California, in constant (1982-84) dollars, derived by BLS from the Current Population Survey[(c)]
4	I_t = Real Incomes in Year t	367	Median Usual Weekly Earnings (MUWE), in constant (1982-84) dollars, derived by BLS from the Current Population Survey[(d)]
5	VSL_t = VSL in Current Base Year	$13.2 million	See Table 2 for calculation details
6	$VSL_{t,CA}$ = VSL in Current Base Year, California	$15.2 million	

(a) Consumer Price Index - California. Note that this data series is indexed using the same base year as BLS CPI-U Series CUUR0000SA0 used in the DOT VSL. Available at: https://www.dir.ca.gov/OPRL/CPI/EntireCCPI.PDF.

(b) BLS Series CUUR0000SA0. Available at: https://data.bls.gov/timeseries/CUUR0000SA0.

(c) BLS Series LEU0252881506 (California median weekly earnings in current dollars). Available at: https://data.bls.gov/timeseries/LEU0252881506. Current dollar values are deflated to constant (1982-84) dollars using the BLS CPI-U Series CUUR0000SA0. Available at https://data.bls.gov/timeseries/CUUR0000SA0.

(d) BLS Series LEU0252881600. Available at: https://data.bls.gov/timeseries/LEU0252881600.

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28 Calculation details are provided in workpaper Exhibit (PG&E-2) RM-RMCBR-6.

b. Electric Reliability Attribute

The RDF Proceeding Phase II Decision requires each IOU to use the most current version of the Lawrence Berkeley National Laboratory Interruption Cost Estimate (ICE) Calculator to determine a standard dollar valuation of electric reliability risk for the Reliability Attribute.[29]

As shown in Figure 2-1, the main output section of the ICE Calculator produces results for three customer classes – Medium and Large Commercial and Industrial (C&I),[30] Small C&I, and Residential – as well as the average results for all customer classes, weighted by the number of customers in each class.

FIGURE 2-1
ICE CALCULATOR MAIN OUTPUT (CALIFORNIA DATA)

Reliability Inputs:

SAIFI	2.000
SAIDI	120.0
CAIDI	60.0

Number of Customers:

Non-Residential	1,000
Residential	10,000

Main Output:

Sector	No. of Customers	Cost Per Event (2016$)	Cost Per Average kW (2016$)	Cost Per Unserved kWh (2016$)	Total Cost of Sustained Interruptions (2016$)
Medium and Large C&I	169	$8,444.8	$161.2	$161.2	$2,854,333.0
Small C&I	831	$643.6	$311.5	$311.5	$1,069,733.4
Residential	10,000	$5.3	$6.5	$6.5	$106,819.7
All Customers	11,000	$183.2	$107.3	$107.3	$4,030,886.1

Results shown in Figure 2-1 are for California customers and include *Cost Per Event, Cost Per Average kW, Cost Per Unserved kWh* and *Total Cost of Sustained Interruptions*, all expressed in $2016. Table 2-5 provides additional detail on how the main output results are calculated.

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29 Lawrence Berkeley National Laboratory ICE Calculator, available at: <https://icecalculator.com/assets/Module_1-Estimate_Interruption_Costs_v2.0.xlsm> (accessed May 2, 2024).

30 The ICE Calculator categorizes Medium and Large C&I as customers with annual electricity usage exceeding 50,000 kWh.

TABLE 2-5
ICE CALCULATOR MAIN OUTPUT CALCULATIONS

Line No.	Output	Calculation
1	Cost Per Event	Result from ICE Calculator's Econometric Model
2	Cost Per Average kW	$(Cost\ Per\ Event)/(Annual\ Average\ MWh \times 1{,}000/8{,}760)$
3	Cost Per Unserved kWh	$(Cost\ Per\ Event)/(Annual\ Average\ MWh \times 1{,}000/8{,}760 \times CAIDI/60)$
4	Total Cost of Sustained Interruptions	$Cost\ Per\ Event \times SAIFI \times No.of\ Customers$
5	SAIFI (System Average Interruption Frequency Index)	$(Total\ No.of\ Customer\ Interruptions)/(Total\ No.of\ Customers)$
6	SAIDI (System Average Interruption Duration Index)	$(Sum\ of\ All\ Customer\ Interruption\ Durations)/(Total\ No.of\ Customers)$
7	CAIDI (Customer Average Interruption Duration Index)	$SAIDI/(SAIFI) = (Sum\ of\ All\ Customer\ Interruption\ Durations)/(Total\ No.of\ Customer\ Interruptions)$

Since the ICE Calculator relies upon national and state-level data inputs, PG&E elected to update some of the California data inputs with PG&E-specific data. This includes updating customer class data (number of customers in each class as well as annual average usage) manufacturing percent of C&I customers, reliability inputs, and outage distributions by time of day and season. Figure 2-2 shows the updated output results using PG&E data.

FIGURE 2-2
ICE CALCULATOR MAIN OUTPUT (PG&E DATA)

Reliability Inputs:

SAIFI	1
SAIDI	120
CAIDI	120

Number of Customers:

Non-Residential	633,547
Residential	4,961,426

Main Output:

Sector	No. of Customers	Cost Per Event (2016$)	Cost Per Average kW (2016$)	Cost Per Unserved kWh (2016$)	Total Cost of Sustained Interruptions (2016$)
Medium and Large C&I	163,960	$7,361.8	$268.0	$134.0	$1,207,044,839
Small C&I	469,587	$943.9	$540.5	$270.2	$443,266,064
Residential	4,961,426	$5.2	$9.0	$4.5	$25,973,708
All Customers	**5,594,973**	**$299.6**	**$204.1**	**$102.1**	**$1,676,284,611**

Table 2-6 summarizes the default California data and PG&E-specific data used in the ICE Calculator to produce the results shown in Figure 2-2.[31]

[31] PG&E data used in the ICE Calculator is provided in Workpaper (WP) RM-RMCBR-9.

TABLE 2-6
USER INPUT VALUES USED IN ICE CALCULATOR

Line No.	ICE Calculator Input	User Input Default	User Input Used	Source
1	*Number of Customers*[(a)]			
	Non-Residential	1,000	633,547	2023 recorded accounts
	Residential	10,000	4,961,426	data
2	*Number of Accounts by Rate Class*			
	Residential	12,971,924	4,961,426	
	Small C&I	1,567,550	469,588	2023 recorded accounts
	Medium and Large C&I[(b)]	319,434	163,960	data
3	*Annual Usage per Customer (MWh)*			
	Residential	7.2	5.1	
	Small C&I	18.1	15.3	
	Medium and Large C&I	459.0	240.6	2023 recorded usage data
4	*Medium and Large C&I*[(c)]			
	Manufacturing	17.1%	9.5%	2020-2022 recorded data;
	GDP / kWh (Non-residential)	$15.11	$15.11	User Input Default (2016)
5	*Small C&I*			
	Construction[(d)]	9.5%	9.5%	User Input Default for CA;
	Manufacturing	5.0%	7.1%	2020-2022 recorded data;
	Backup generation or Power conditioning	26.2%	26.2%	User Input Default for CA;
	Backup generation and Power conditioning	3.4%	3.4%	User Input Default for CA
6	*Residential*			
	Household Income	$56,862	$56,862	User Input Default for CA
7	*Reliability Inputs*			
	SAIFI	2.00	1.00	SAIFI set to 1 in order to get per-outage reliability value;
	CAIDI	120.00	120.00	CAIDI based on recorded annual average data from 2013-2022[(e)] ;
	SAIDI	60.00	120.00	SAIDI=SAIFI*SAIDI

TABLE 2-6
ICE CALCULATOR INPUTS – ICE DEFAULT (CALIFORNIA) DATA AND USER INPUT USED (CONTINUED)

Line No.	ICE Calculator Input	ICE Data	PG&E Data	PG&E Data Source
8	*Outages by Time of Day*			
	Morning (6 am to 12 pm)	25%	13%	
	Afternoon (12 pm to 5 pm)	21%	23%	
	Evening (5 pm to 10 pm)	21%	28%	Electric Operations unplanned
	Night (10 pm to 6 am)	33%	36%	outage data from 2016-2022
9	*Outages by Time of Year*			
	Summer (June through September)	50%	29%	Electric Operations unplanned
	Non-Summer (October through May)	50%	71%	outage data from 2016-2022

(a) The ICE Calculator uses the percent split between small C&I and medium and large C&I accounts to allocate the number of non-residential customers entered on the main input into those two C&I subcategories.
(b) PG&E's Medium and Large C&I category includes light and power customers plus agriculture customers.
(c) Manufacturing is the only C&I category (Medium and Large C&I, and Small C&I) with PG&E-specific data.
(d) Construction values were not updated from the default values due to the lack of the data.
(e) See PG&E's 2022 Safety and Operational Metrics Report (April 3, 2023), Chapter 2.

Consistent with its 2020 RAMP Report filing, PG&E's preference is to define the Electric Reliability metric as Cost per Customer Minute Interrupted ($/CMI), where:

$$\frac{\boldsymbol{Cost}}{\boldsymbol{CMI}} = \frac{Cost\ Per\ Event}{SAIDI} = \frac{Cost\ Per\ Event \times Total\ No.of\ Customers}{Sum\ of\ All\ Customer\ Interruption\ Durations}$$

Since the ICE Calculator outputs are expressed in $2016 PG&E is using the BLS Consumer Price Index for All Urban Consumers (CPI-U) series to adjust the $2016/CMI results to $2023/CMI:

$$\left(\frac{\boldsymbol{Cost}}{\boldsymbol{CMI}}\right)_{\boldsymbol{t}} = \left(\frac{\boldsymbol{Cost}}{\boldsymbol{CMI}}\right)_{\boldsymbol{0}} \times \left(\frac{P_t}{P_0}\right)$$

Table 2-7 summarizes the calculation details to adjust the $/CMI to $2023, and Figure 2-3 shows the resulting $/CMI values for each customer class, including a comparison of results using the ICE default California data and the PG&E-specific data.[32]

[32] The ICE Calculator updated with PG&E data is provided in Exhibit (PG&E-2), WP RM-RMCBR-8.

TABLE 2-7
COST/CMI CALCULATION DETAILS

Line No.	Element	Value	Data Source
1	*0* = Original Base Year	2016	
2	*t* = Current Base Year	2023	
3	P_0 = Price Index in Original Base Year	240.007	BLS Consumer Price Index for All Urban Consumers (CPI-U)
4	P_t = Price Index in Year *t*	304.702	

FIGURE 2-3
$/CMI USING ICE DEFAULT DATA AND PG&E-SPECIFIC DATA

	ICE Data (California)		PG&E Data	
Sector	Cost per CMI (2016$)	**Cost per CMI (2023$)**	Cost per CMI (2016$)	**Cost per CMI (2023$)**
Medium and Large C&I	$70.37	$89.34	$61.35	$77.89
Small C&I	$5.36	$6.81	$7.87	$9.99
Residential	$0.04	$0.06	$0.04	$0.06
All Customers	**$1.53**	**$1.94**	**$2.50**	**$3.17**

c. Gas Reliability Attribute

D.22-12-027 requires each IOU to apply a dollar value for gas reliability based on the implied value from their most recent Multi-Attribute Value Function (MAVF) Risk Score calculation presented in their most recent RAMP or to justify its choice of an alternative model by providing an analysis comparing the results of its preferred alternative model to the results using the implied values.

PG&E explored the feasibility of choosing an alternative model. However, given the time constraints and limited available data PG&E decided to use the implied dollar value for gas reliability derived from PG&E's MAVF as described and applied in the 2020 RAMP filing. The dollar value for Gas Reliability, expressed in $2023 is $1,569.75 per gas customer and is derived using the formula below:

$$VGA_t = VGA_0 \times \left(\frac{P_t}{P_0}\right) = \left(\frac{UB_F}{UB_G} \times \frac{wt_G}{wt_F}\right) \times \left(\frac{P_t}{P_0}\right)$$

Table 2-8 summarizes the calculation details.[33]

TABLE 2-8
GAS RELIABILITY ATTRIBUTE CALCULATION DETAILS

Line No.	Element	Value	Notes and Data Sources[a]
1	*0* = Original Base Year	2020	
2	*t* = Current Base Year	2023	
3	P_0 = Price Index in Original Base Year	258.811	BLS Consumer Price Index for All Urban Consumers (CPI-U)[b]
4	P_t = Price Index in Year t	304.702	
5	UB_F = Upper Bound of Financial Attribute in MAVF	$5 Billion	The Upper Bound of the Financial Range represents a financial loss commensurate with a 2000-2001 Energy Crisis-type event.
6	UB_G = Upper Bound of Gas Attribute in MAVF	750,000 customers	The Gas Reliability Upper Bound is based on a scenario of an outage at a critical gas facility.
7	wt_F = Weight of Financial Attribute in MAVF	25%	In developing the MAVF for the 2020 RAMP, PG&E assigned the Attribute Weights to reflect the relative importance of moving each Attribute from its least desirable level (i.e., Upper Bound) to its most desirable level (i.e., zero).
8	wt_G = Weight of Gas Attribute in MAVF	5%	
9	VGA_0 = Value of Gas Reliability Attribute	$1,333.33	Natural Unit for Gas Attribute is 'Gas Customer.
10	VGA_t = Value of Gas Reliability Attribute	$1,569.75	

(a) Weights and Ranges associated with PG&E's MAVF Attributes are described in detail in PG&E's 2020 RAMP Report, A.20-06-012 (June 30, 2020), Chapter 3.
(b) BLS Series CUUR0000SA0. Available at: https://data.bls.gov/timeseries/CUUR0000SA0.

d. Inflation Adjustment for Future Years

Some risk mitigation programs provide risk reduction benefits over multiple years; therefore, PG&E must calculate monetized risk attribute values for each year over the expected life of the risk reduction from a risk mitigation program. Since public data used in the monetized attribute value calculations is only available through 2023, PG&E is applying an annual escalation multiplier to the 2023 monetized risk attribute values for future years. For the escalation multiplier, PG&E is using the average annual Consumer Price Index for All Urban

[33] Calculation details are provided in Exhibit (PG&E-2), WP RM-RMCBR-10.

Consumers (CPI-U) growth forecast of 2.3% from *The 2023 Long-Term Budget Outlook* published by the Congressional Budget Office.[34]

Note that PG&E shows risk values for future years in 2023 real dollars (i.e., stripping out the inflation impact), rather than in nominal dollars, for easier comparison of annual risk values over different years.

6. Implementing CBA Principle 6 – Risk-Adjusted Levels

CBA Principle 6 requires Utilities to apply a Risk Attitude Function (also known as a Risk Scaling Function) to the Monetized Levels of an Attribute or Attributes to obtain Risk-Adjusted Levels, as determined by the RDF Proceeding Phase II Decision.[35] CBA Principle 6 provides that "The Risk Attitude Function specifies attitude towards different kinds of Outcomes including capturing aversion to extreme Outcomes or indifference over a range of Outcomes"[36] and that the "The Risk Attitude Function can be linear or non-linear"[37] For example, the Risk Attitude Function is linear to express a risk-neutral attitude if avoiding a given change in the Monetized Attribute Level does not depend on the Attribute Level. Alternatively, the Risk Attitude Function is non-linear to express a risk-averse or risk-seeking attitude if avoiding a given change in the Monetized Attribute Level differs by the Attribute Level.

Row 24 of the RDF further requires the "Use of Expected Value for CoRE", where CoRE is defined in Row 13 as "the sum of each of the Risk-Adjusted Attribute Values using the utility's full Cost-Benefit Approach",[38] i.e., the Risk-Adjusted Levels from Principle 6 above. Hence the expected value from Row 24 reflects risk attitudes; it can be either the risk-neutral, risk-seeking or risk-averse expected value depending on the Risk Scaling Function used. A risk-neutral attitude is expressed as a Risk

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[34] Congressional Budget Office, The 2023 Long-Term Budget Outlook (June 2023), Long-Term Economic Projections that support Table 3-1, available at: <https://www.cbo.gov/system/files/2023-06/57054-2023-06-LTBO-econ.xlsx> (accessed May 2, 2024).

[35] D.22-12-027, Appendix A, p. A-8, No. 7.

[36] D.22-12-027, Appendix A, p. A-8, No. 7.

[37] D.22-12-027, Appendix A, p. A-8, No. 7.

[38] D.22-12-027, Appendix A, p. A-13, No. 13.

Scaling Function that is simply the identity function. Hence a risk-neutral expected value is also referred to as the Unscaled Expected Value. However, when a Scaling Function that is something other than a 1.0 multiplier is used, its expected value is referred to as the Risk-Adjusted (or Scaled) Expected Value. The ratio of the putative Risk-Adjusted Expected Value to Unscaled Expected Values is known as the Risk Premium multiplier.[39] A risk-averse attitude will result in a Risk Premium multiplier greater than 1.0, i.e., the participant is willing to pay up to some amount, as determined by their degree of risk aversion, over the Unscaled Expected Value to mitigate the risk. Conversely, if the Risk Premiums can be observed, the degree of risk aversion and correspondingly the associated Scaling Function, can be inferred. PG&E employs the latter approach to develop its Risk Scaling Function as follows.

As described in Section B above, PG&E's risk management objective is to prioritize the mitigation of risks characterized as low frequency/high consequence events, even though their expected loss might be the same as multiple high frequency events with low consequences. To reflect this objective, PG&E adopts a market-based approach to developing Risk Scaling Functions such that the Function(s):

1) Does not lower the expected monetized value of the Attribute levels (i.e., not risk-seeking).
2) Notwithstanding the above, results in values consistent with prices and/or estimates from risk transfer markets, and/or public policy towards risk transfer, <u>to the extent such pricing is applicable and available</u>.

PG&E's approach, at its core, is to use available, objective data to determine the Risk Scaling Function(s). Risk Premiums/Prices from Insurance and Capital Markets meet these criteria because they are for products from independent entities that mitigate the same underlying risk presented in this Report such as wildfires, Loss of Containment (LOC) on gas pipelines, cyber-attacks, etc. These market prices encode preferences. As such, they can be used to develop empirically based Risk Scaling

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39 It is also common for the Risk Premium to be expressed as the *difference* between the Risk-Adjusted and Unscaled Expected Values.

Function(s) that will be more insightful and representative than any approach considered to date.

The market-based approach creates consistency and alignment. The Commission already oversees PG&E's Insurance and Capital Markets activities; therefore, creating a tie between the RDF and Insurance and Capital Markets would create consistent and complementary policies and decisions. The Commission and IOUs can look to the markets to assist in ascertaining the value of mitigations (i.e., the efficient allocation of capital). As mitigation programs are deployed, the amount of risk is reduced, which all other things being equal, would reduce the premiums demanded by insurers and other market participants.

Market theory tells us that the prices obtained from a perfect market maximize value to society. Of course, no market is perfectly competitive, complete, or truly representative of societal preferences—for instance, in addressing ESJ concerns—but there are established practices that can be employed within the market-based approach to account for shortcomings while still preserving its function of communicating societal values. Hence, Risk Scaling Function(s) developed to be consistent with market prices would represent societal risk preferences, not the IOU's.

In summary, PG&E's objective is to use available market data to determine the fair value of risk and mitigations. Incorporating market data, via the Risk Scaling Function, does not compel ratepayers to purchase insurance or other risk transfer policies. PG&E's insurance activities are already under the oversight of the Commission and addressed in General Rate Case Applications,[40] and nothing herein interferes with or impacts PG&E's existing insurance program and its oversight. Neither does using market information compel ratepayers to fund mitigations. Markets are often used to determine the fair value of goods and services, but whether one should obtain the said goods or services is dependent on individual circumstances. Hence, market data (from insurance and other risk transfer

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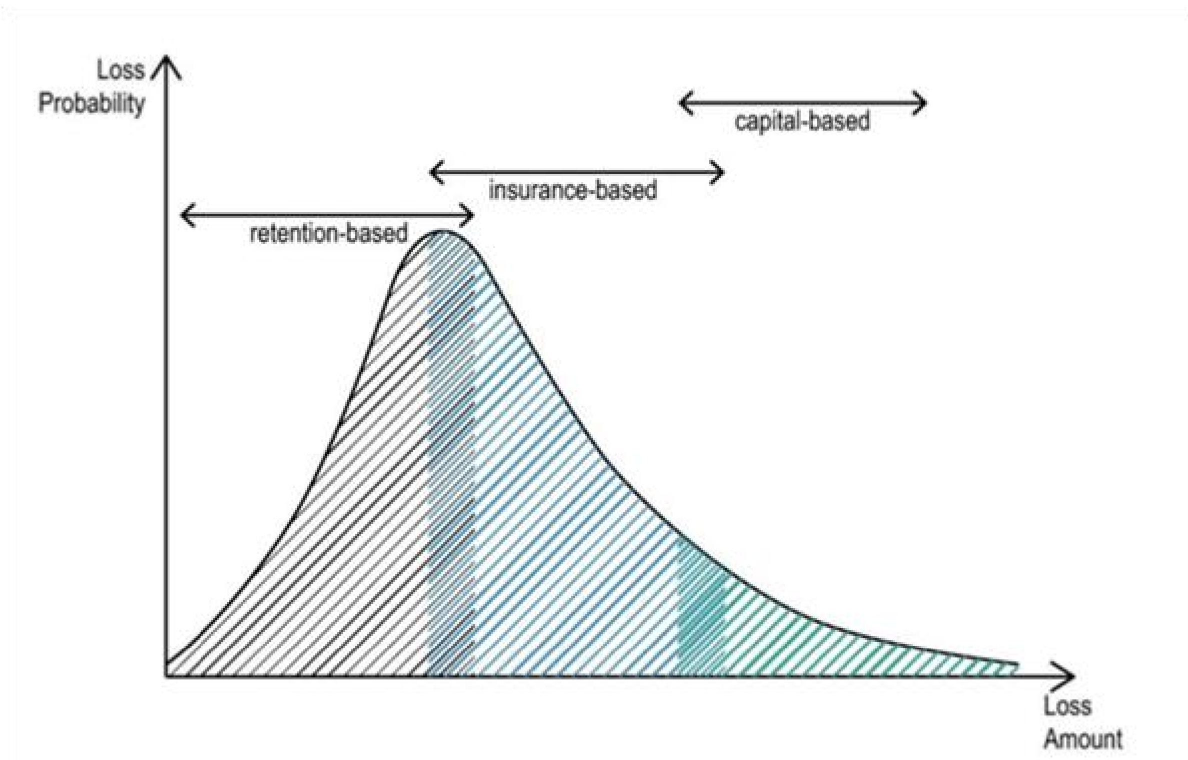
40 D.14-08-032, p. 550 ("Procuring excess liability insurance is a reasonable business practice;"); p. 713, Findings of Fact 260 ("Ratepayer funding of insurance premiums offers a reasonable way to limit risks of large, unforeseeable loss of utility property due to natural catastrophes.")

markets) can be used, in part, to determine the value of mitigations, and whether to fund such programs is part of the IOU's General Rate Case process, and should include budget considerations, overall priorities, risk tolerance and other factors.

a. Applicable Markets

To determine which markets, i.e., the set of prices or premiums to use for inferring its Scaling Function, PG&E relies on the following observations. In the management of losses by firms, a general three-tier risk financing strategy can be employed.[41] Figure 2-4 below illustrates the financial loss distribution that a corporation faces and how it employs different risk-transfer approaches for the different parts of the distribution.

FIGURE 2-4
THREE-TIERED RISK FINANCING STRATEGY



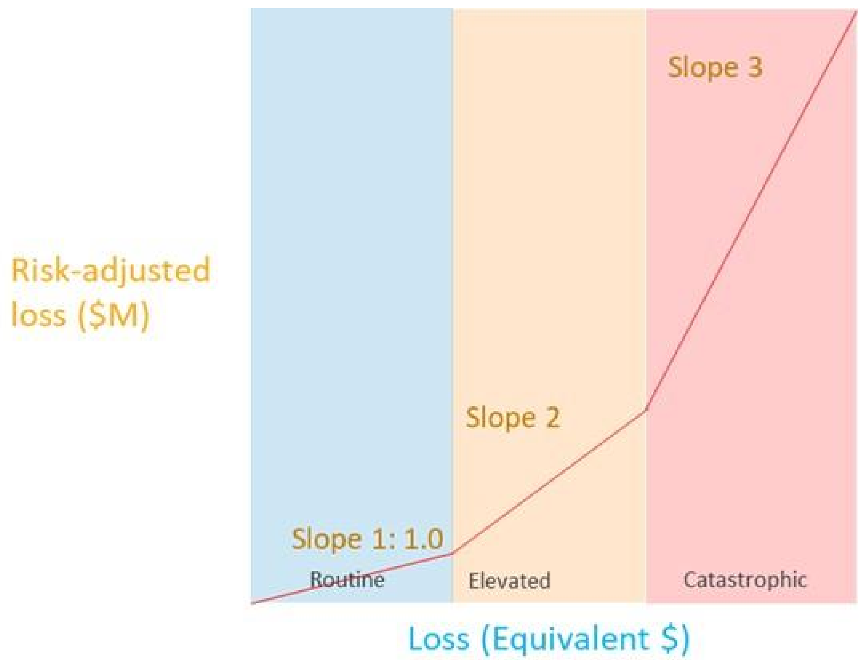
[41] Carolyn Kousky, et al., Wharton Risk Management and Decision Processes Center, Financing Third Party Wildfire Damages: Options for California's Electric Utilities (Feb. 2019).

- *Retention-based tier:* For high frequency/minor-loss risks, firms often assume "deductible" amounts in insurance contracts, i.e., they will assume the losses under a certain amount.
- *Insurance-based tier:* For lower probability / higher magnitude risks (compared to the Retention-based tier), losses are transferred to insurance companies. Policies underwritten by insurance companies have deductible and coverage amounts that specifically limit losses to this region. For example, a policy could have a $10 million deductible and a $100m coverage limit, meaning that only losses above $10 million are covered, and total compensation is capped at $100 million. Hence it follows that the policy premiums represent the degree of risk aversion for this range of losses, as determined by the insurance markets.
- *Capital-based/Catastrophic tier:* Transfer tail/catastrophic risks (low probability/extreme loss) transfer to capital markets and reinsurers via catastrophic (CAT) bonds and other products. The prices for these products are the risk premiums, i.e., the degree of risk aversion, for losses of catastrophic magnitude.

b. Proposed Risk Scaling Function Functional Form

Corresponding to the three-tiered strategy, a three-segment Risk Scaling Function is employed for each of the Attributes. The Function is piece-wise linear, i.e., each segment is linear with slopes (corresponding directly with Risk Premium multipliers) determined from the markets described above.

FIGURE 2-5
FUNCTIONAL FORM OF PG&E'S RISK SCALING FUNCTION



1) *Routine (minor) region:* The first segment corresponds to the Retention-based tier. The first segment has the slope set to 1.0 indicating a preference by rate-payers to be risk-neutral for minor/small-scale losses.

2) *Elevated (serious) region:* The second segment has its slope, *slope 2*, set to a value of 2.0. This is based on two sources:

   i. Data from the National Association of Insurance Commissioners[42] that showed that Pure/Direct Loss Ratios (Losses/Premiums, i.e., the inverse of the Risk Premium multiplier) for 2014-2023 for Commercial Multiple Perils policies ranged from 5 percent to 58 percent, implying a multiplier/slope of between 1.72 to 1.81.

   ii. Indicative pricing obtained in 2021 from PG&E's insurance broker indicated a multiplier/slope of approximately 2.33 for both Wildfire and non-Wildfire risks.

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[42] National Association of Insurance Commissioners, US Property & Casualty and Title Insurance Industries, 2023 First Half Results, available at: <https://content.naic.org/sites/default/files/inline-files/cipr-report-property-casualty-mid-year-2023.pdf> (accessed May 2, 2024).

3) *Catastrophic region:* The third segment represents the Capital-based/Catastrophic tier and its slope, *slope 3*, is set to 7.5 based on available Risk Premiums from Catastrophic Bond market transactions, which can be found at the Artemis Catastrophe Bond & Insurance-Linked Securities Deal Directory.[43] Table 2-9 below summarizes the transactions available, for both Wildfire and non-Wildfire (Cyber) risks, demonstrating that PG&E's multiplier is reasonable because it is within the range of prices seen.

TABLE 2-9
CAT BOND DATA SUMMARY

Line No.	Issue	Risk	Date	Attachment	Coverage	Premium Multiplier
1	PG&E Cat Phoenix Re	Wildfire	Aug 2018	$1.25b	$200m	7.5
2	Sempra SD Re Ltd (series 2018-1)	Wildfire	Oct 2018	$1.326b	$125m	19
3	Sempra SD Re Ltd (series 2020-1)	Wildfire	Jul 2020	$1b	$90m	5-4 - 6.4
4	LA DWP Power Protective RE Ltd (series 2021-1)	Wildfire	Dec 2020	$125m	$50m	15 - 18
5	Sempra SD Re Ltd (series 2021-1) class B	Wildfire	Oct 2021	$1.2b	$135m	5 – 6
6	LA DWP Power Protective Re Ltd (series 2021-1)	Wildfire	Oct 2021	$125m	$30m	20 - 23
7	PoleStar Re Ltd (series 2024-1)	Cyber	Dec 2023	N/A	$140m	10.3
8	Matterhorn Re Ltd (Series 2023-1)	Cyber	Dec 2023	N/A	$50m	7.0
9	East Lan Re VII Ltd (Series 2024-1)	Cyber	Dec 2023	N/A	$150m	6.7
10	Long Walk Reinsurance Ltd (Series 2024-1)	Cyber	Nov 2023	N/A	$75m	5

Loss Region Determination

Unlike the slopes/multipliers, which do not vary by Attribute, the range of losses (in dollars) that make up the regions above are determined on a per-Attribute bases. This is to reflect and be consistent with how PG&E operationally manages the different sub-Attribute consequences.

The dollar ranges corresponding to the loss regions for the Financial Attribute are based on the current risk financing environment facing PG&E, while the dollar loss ranges for the Safety and Gas Reliability Attributes are based on orders of magnitude of losses, consistent with

43 Artemis, Catastrophe Bond & Insurance-Linked Securities Deal Directory, available at: <https://www.artemis.bm/deal-directory/> (accessed May 2, 2024).

the region characterization (routine, serious, catastrophic). Table 2-10 below summarizes the dollar ranges that comprise the loss regions for the Financial, Safety and Gas Reliability Attributes.

TABLE 2-10
RANGES FOR THE RISK SCALING FUNCTION

Line No.	Loss Region	Financial	Safety	Gas Reliability
1	Routine	$0 - $10m Based on common deductible amounts for PG&E's policies.	0 – 1 EF / $0 - $15.2m Represents ~1% of largest probable event (100 EF).	0 – 7.5k customers impacted Represents ~1% of largest probable event (750,000 customers impacted).
2	Elevated	$10m - $1b AB 1054 Wildfire Fund "attaches" at $1b, i.e., assumes that IOUs carry coverage up to $1b.	1 – 10 EF / $15.2 - $152m Between 1% - 10% of largest probable event.	7.5k – 75k customers impacted Between 1% - 10% of largest probable event.
3	Catastrophic	Over $1b Consistent with AB 1054 in that coverage above this level is difficult to obtain from insurance markets.	Over 10 EF / $152m Over 10% of largest probable event.	Over 75k customers impacted Over 10% of largest probable event.

For the Electric Reliability Attribute, the two breakpoints of the Risk Scaling Functions were obtained based on the magnitude of customer interruptions that constitute routine, elevated and catastrophic outage events, as documented in PG&E's 2023 Company Emergency Response Plan (CERP) and relating the incident levels with estimated Storm Outage Prediction Program (SOPP) model results for forecasted CMI of corresponding category. The Incident Classification Table of the CERP, shown in Figure 2-6 below, identifies Catastrophic Electric Reliability events have a Classification Level of 5. Cross-referencing the SOPP model results, this roughly translates to a magnitude of 1 billion CMI or more. Similarly, the Elevated range corresponds to events that have a magnitude of between 100m to 1b CMI, while the Routine range represent events below 100m CMI.

FIGURE 2-6
CERP INCIDENT CLASSIFICATION

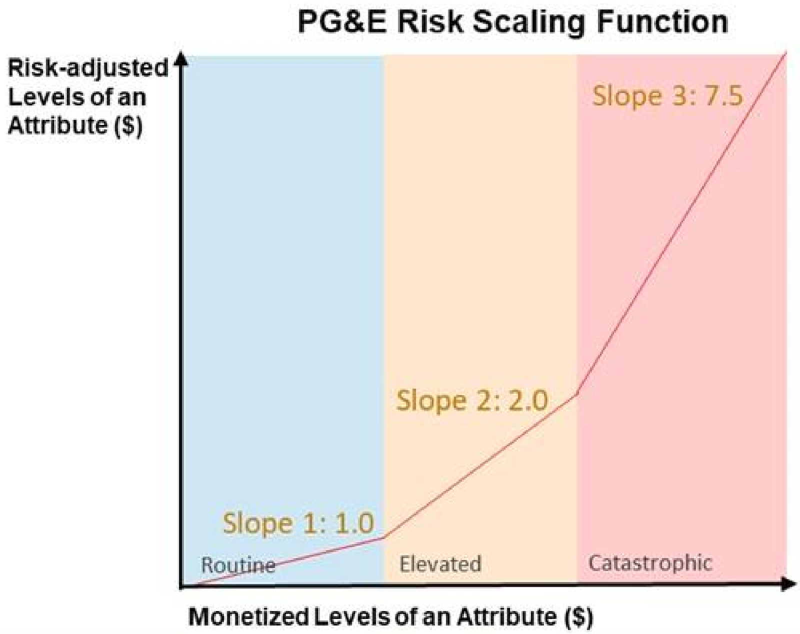
Level		Response
Catastrophic	5	• Incident includes multiple emergencies, affects many customers, business operations • Significant cost and infrastructure risk/damage • Full mobilization of PG&E, contractor and mutual aid resources • May have heavy media interest and actual reputational risk • EOC and Executive Team are activated
Severe	4	• Incident includes extended multiple incidents and affects many customers • Escalating company impact • Resources, contractors and mutual aid may be shared between region • May have heavy media interest and potential reputational risk
Serious	3	• Incident involves large numbers of customers • Resources may need to move between regions • Potential increased, actual or imminent negative media interest
Elevated	2	• A pending or local incident that requires more than routine operations • Resources may need to move within the region • Increased media interest
Routine	1	• Incident involves a relatively small number of customers • Local resources are sufficient • Little to no media coverage

TABLE 2-11
ESTIMATED CMI THRESHOLD BY CATEGORY

SOPP Forecasted of Entire PG&E system	Category 1	Category 2	Category 3	Category 4	Category 5
Estimated Lower Range of Forecasted CMI of Peak Day for EOC Activation	50M	100M	200M	350M	1B

PG&E's Risk Scaling Function as applied to the different Attributes is summarized in Figure 2-7 below. To determine the dollar ranges from the CMI ranges above, the Value of Service of $3.17/CMI is applied.

FIGURE 2-7
RISK SCALING FUNCTION CALIBRATION PARAMETERS



Attribute	Routine	Elevated	Catastrophic	
Financial	$0 - $10m	$10m - $1b	$1b+	
Safety	0 – 1 EF $0 - $15.2m	1 – 10 EF $15.2m - $152m	10+ EF $152m+	$15.23m/ EF
Electric Reliability	0 - 100m CMI $0 - $317m	100 – 1,000m CMI $317m – $3.17b	1,000m+ CMI $3.17b+	$3.17/CMI
Gas Reliability	0-7.5k cust $0 - $11.5m	7.5k - 75k cust $11.5m – 115m	75k+ cust $115m+	$1,570 / customer

D. Risk Assessment

This section describes how PG&E implemented Step 3, Mitigation Analysis for Risks in RAMP. The objective of this section is to explain the methodology used to develop the 12 models which probabilistically assess the likelihood and consequence of the Risks reported in PG&E’s 2024 RAMP Report. Each of these models produces a 2027 Baseline Risk Score, which is calculated using the methodology discussed in Section D.1.d, below.

1. Bow Tie Methodology

Each of the RAMP risk chapters present a risk Bow Tie, which provides a visual representation of the risk event, the drivers, driver frequency and risk contribution and of the outcomes, outcome frequency, risk contribution and CoRE. In the center of the Bow Tie is the risk event, which is a well-defined, single, observable, and measurable event. In the example Bow Tie below, Figure 2-8, the Risk Event is a Loss of Containment (LOC) on Gas Transmission Pipeline.

In the following sections PG&E describes each of the Bow Tie elements: drivers/frequency; outcomes/consequences; the risk value; and the cross-cutting factors.[44] The definition and use of these Bow Tie elements are consistent with PG&E's 2020 RAMP.

The risk value shown at the bottom of the Bow Tie, in the center, is calculated as the frequency of the risk event (a function of likelihood of the risk event, or LoRE, and the total risk exposure) multiplied by the consequence of the risk event (Frequency x CoRE).[45] Calculating the risk value is described in more detail below.

The risk value is expressed in units of millions of risk-adjusted dollars (abbreviated as $M risk adj.), which is how the CoRE is expressed. The $M follows from the application of the CBA; risk event consequences are monetized under this approach. The risk adjustment follows from the application of the Risk Attitude Function. The risk value can be interpreted as the willingness to pay to completely transfer the risk to a third party (per year).

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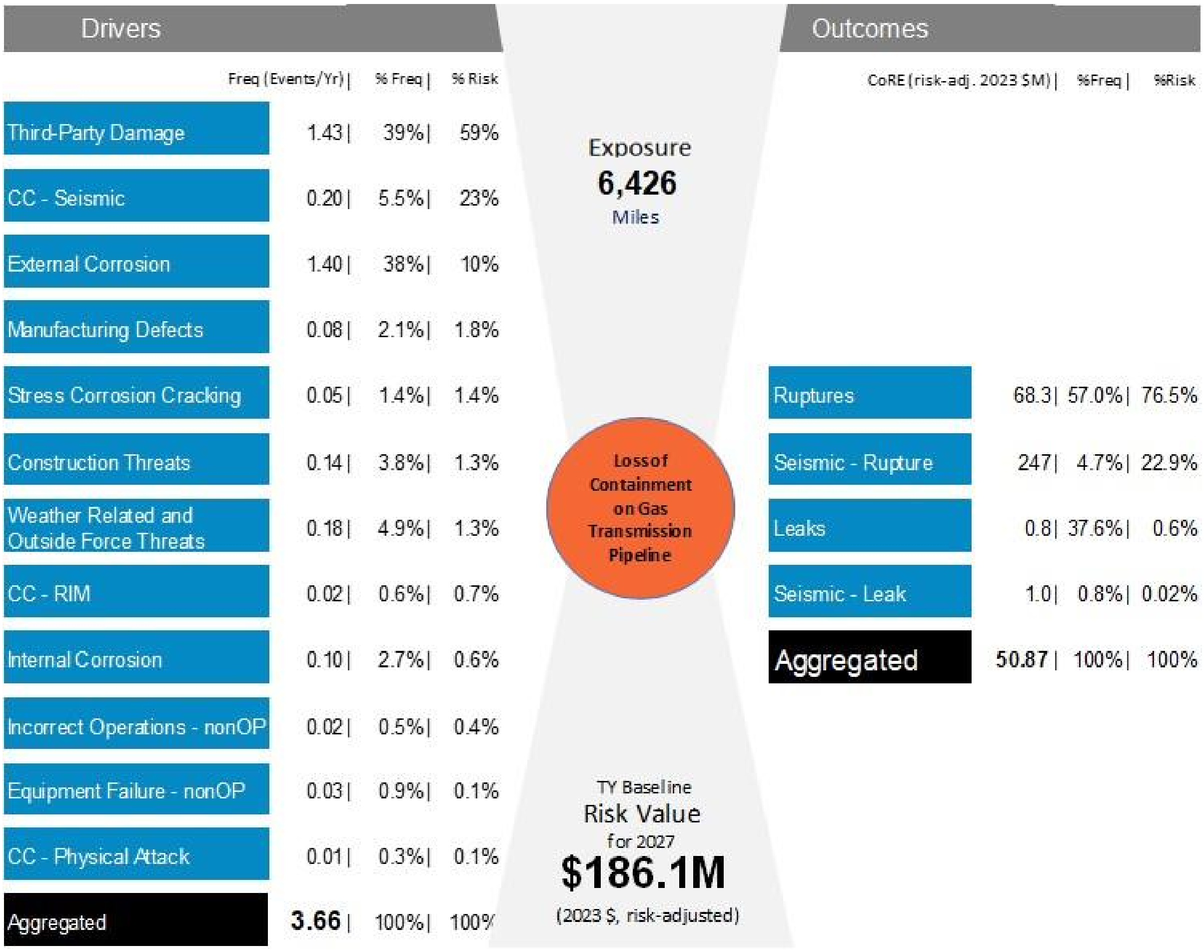
44 Cross-cutting factors are not risk events themselves but rather they impact either the likelihood or consequence of other risk events. The cross-cutting factors are shown on the left side of the Bow Tie preceded by the letters "CC." On the right side of the Bow Tie, they are shown in combination with other consequence events.

45 Note that the multiplication of the Aggregated Frequency and the Aggregated CoRE shown in the Bow Tie may not be the same as the Risk Score (or Risk Value) shown in the middle of the Bow Tie due to rounding.

FIGURE 2-8
RISK EVENT BOW TIE: LOSS OF CONTAINMENT ON GAS TRANSMISSION PIPELINE



a. Frequency of a Risk Event

On the left-hand size of the Bow Tie are the Risk Event drivers (or risk drivers) and their associated frequencies. The set of drivers includes the causes or threats identified for the Risk Event. Drivers are measurable events. The annual frequency of a risk driver leading to a Risk Event is informed by PG&E event data that is supplemented with industry data and/or SME input when necessary. Certain drivers are further divided into multiple sub-drivers (components of a risk driver),[46] where the division is useful and where data are available. Risk and mitigation analysis can also be done at a sub-driver level.

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[46] For example, the risk driver "Vegetation" in the Failure of Electric Distribution Overhead Assets risk event includes three sub-drivers: tree contract; right-of-way encroachment; and tree trimming.

Drivers are expressed as the frequency of occurrence of a Risk Event per unit of exposure *per year*, the time unit for the analysis. For example, Figure 2-8 shows a frequency of 1.43 for the Third-Party Damage driver (top left side of the figure) which means that in 2027 PG&E expects to have 1.43 LOC events on a gas transmission pipeline due to third-party damage events (assuming no further mitigations in 2027). The frequency of a Risk Event associated with each driver is summed to establish the risk-level frequency. Considering all drivers, PG&E expects to have 3.7 LOC events—the aggregated number of events shown in the lower left corner of the Bow Tie.

b. Potential Consequence of a Risk Event

On the right-hand side of the Bow Tie, PG&E uses Outcomes to differentiate manifestations of a risk event that have significantly different consequences (changes in Attribute levels representing the impact of the outcome). Each Outcome is characterized by different probability distributions over the applicable Attributes, determined from PG&E data, industry data, and/or SME input. The consequences of the Risk Event are shown in more detail in the Consequence Table in each RAMP risk chapter and in the associated Bow Tie model workpaper.[47] Figure 2-9 below is the Consequence Table for the LOC on Gas Transmission Pipeline risk.

[47] The Bow Tie workbook, from which the Bow Tie graphics are pulled, is one of the modeling workpapers made available to support each risk chapter. The Bow Tie workbook is the second workpaper in each set (e.g., GO-LOCTM-02 for the example risk event). The consequence table is included in the *Conseq* tab. Guidance on how to use the interface in the Bow Tie workbook to explore how granular risk data are aggregated can be found in RM-RMCBR-4.

FIGURE 2-9
CONSEQUENCE TABLE: LOSS OF CONTAINMENT ON GAS TRANSMISSION PIPELINE

Consequences

					Natural Units Per Event			Monetized Levels of a Consequence Per Event (2023 $M/event)			CoRE (risk-adjusted 2023 $M)			Implied Risk-Adjustment Factor			Natural Units per Year			Expected Loss per Year (2023 $M/yr)			Risk Value (risk-adjusted 2023 $M/yr)		
Outcomes	CoRE	%Freq	%Risk	Freq	Safety EF/event	Gas Reliability #cust/event	Financial $M/event	Safety	Gas Reliability	Financial	Safety	Gas Reliability	Financial	Safety	Gas Reliability	Financial	Safety EF/yr	Gas Reliability #cust/yr	Financial $M/yr	Safety	Gas Reliability	Financial	Safety	Gas Reliability	Financial
Ruptures	68.3	57%	77%	2.08	0.71	3,820	3.0	10.8	6.0	3.0	48.9	8.9	10.6	4.5	1.5	3.6	1.47	7,963	6.15	22.45	12.50	6.15	101.85	18.51	22.09
Leaks	0.8	38%	1%	1.37	0.01	102	0.5	0.1	0.2	0.5	0.1	0.2	0.5	1.0	1.1	1.0	0.01	141	0.69	0.13	0.22	0.69	0.13	0.24	0.69
Aggregated	50.9	100%	100%	3.66	0.52	2,498	2.3	8.0	3.9	2.3	37.9	5.9	7.1	4.7	1.5	3.1	1.92	9,141	8.30	29.22	14.35	8.30	138.51	21.54	26.07

In the LOC on a Gas Transmission Pipeline risk above, the consequences of a LOC event include the potential for serious injury or fatality (Safety), loss of gas service (Gas Reliability), and property damage (Financial). The manifestation of these consequences depends on the Outcome that causes the LOC. A leak is sufficiently different from a rupture that modeling them both with a single consequence attribute distribution will not fairly characterize either. Having different sets of Attribute distributions for each Outcome more precisely models the potential consequences of the Risk Event.

The probability distributions characterizing Safety, Financial and Gas Reliability Consequence for the leak outcome are lower in mean and variance across the attributes than the set of distributions for a rupture. Furthermore, some drivers are more or less likely to lead to lower or higher severity outcomes. For example, the Third-Party Damage driver is twice as likely to lead to a rupture as a leak. In contrast, External Corrosion, an important driver of LOC events (10 percent of driver frequency), is nearly 10 times more likely to lead to a leak than to a rupture. Through this analysis, PG&E can better identify and mitigate drivers strongly tied to the more severe outcomes when elements on the left- and the right-hand sides of the Bow Ties are presented with specificity, given the available information.

The Bow Tie illustrated in each RAMP risk chapter lists drivers and outcomes of the Risk Event, as well as the associated summary quantities such as frequency, consequence, and contribution to risk value. Within PG&E's enterprise risk models, those elements can vary by one or more of: time, tranche, sub-driver, outcome, and attribute as summarized in Table 2-12.

TABLE 2-12
SUMMARY OF BOW TIE ELEMENT UNITS AND DIMENSIONALITY

Line No.	Bow Tie Element	Quantification Unit	Can Vary By
1	Exposure	Depends on risk event (e.g., miles of pipe, number of high hazard dams, number of employees)	• Time • Tranche
2	Driver	Expected number of risk events per year (frequency)	• Time • Tranche • Sub-driver • Outcome
3	Outcomes	CoRE	• Time • Tranche • Attribute

c. Tranches

For each Risk Event, underlying the Bow Tie structure is a set of tranches over which driver frequencies and Outcome attribute distributions vary both in applicability and magnitude. Row 14 of the RDF states that “(t)he determination of Tranches will be based on how the risks and assets are managed by each utility, data availability and model maturity, and strive to achieve as deep a level of granularity as reasonably possible.”[48] PG&E has adopted this guidance to create Tranches based on how risks and assets are managed. For example, the Employee Safety Incident Risk includes five tranches—Office Employees and four types of Field Employees— that align with how PG&E manages employee safety based on the nature of their work. Furthermore, since Tranches represent employees who perform similar work, it is reasonable to adopt Row 14’s guidance that “(f)or the purposes of the risk analysis, each element (i.e., asset of system) contained in the identified Tranche would be considered to have homogenous risk profiles (i.e., considered to have the same LoRE and CoRE).”[49] While the Tranches in this RAMP represents PG&E’s best efforts to analyze and manage risks at a granular level, PG&E continually strives to achieve “as deep a level of granularity as

[48] D.22-12-027, Appendix A, p. A-13, No. 14.

[49] D.22-12-027, Appendix A, p. A-13, No. 14.

reasonably possible”. Table 2-13 shows that PG&E has increased the number of tranches for all of the risks presented in the 2020 RAMP in this Application.

TABLE 2-13
COMPARISON OF NUMBER OF TRANCHES FOR RISKS PRESENTED IN BOTH 2020 AND 2024 RAMP

Line No.	Risk Name	2020 RAMP	2024 RAMP
1	Loss of Containment on Gas Transmission Pipeline	4	24
2	Loss of Containment on Gas Distribution Main or Service	12	42
3	Large Overpressure event Downstream of Gas M&C Facility	6	7
4	Wildfire	8	50
5	Failure of Electric Distribution Overhead Assets	5	20
6	Employee Safety Incident	2	5
7	Contractor Safety Incident	1	4

d. Calculating the Risk Value

Each RAMP risk has an associated Risk Value that is the product of the LoRE and the CoRE.[50]

Risk Value per Unit of Exposure = LoRE x CoRE

CoRE is the sum of each of the Risk-Adjusted Attribute Values using the utility’s full CBA. Specifically,

CoRE = Safety CoRE + Electric Reliability CoRE+ Gas Reliability CoRE + Financial CoRE

Where:

- *Safety CoRE = Safety Monetization ($15.2 million/EF) x Safety Unit (# EF)*
- *Electric Reliability CoRE = Electric Reliability Monetization ($3.17/CMI) x Electric Reliability Unit (# CMI)*
- *Gas Reliability CoRE = Gas Reliability Monetization ($1,570/customer) x Gas Reliability Unit (# customers)*

[50] D.22-12-027, Appendix A, p. A-13, No. 13.

- *Financial CoRE = Financial Unit ($, 2023, real)*

PG&E treats LoRE as specified per unit of exposure and expresses Risk Values equivalently as Frequency x CoRE at a Tranche or System level:

Tranche Risk Value = Tranche Exposure x LoRE x CoRE

= Tranche Frequency x CoRE

Risk Value = Sum of Tranche Risk Values over all Tranches for the Risk Event

Frequency (the number of occurrences per year) is a familiar quantity, estimated with varying levels of confidence depending on data availability, operational experience and the underlying nature of the threat (or driver). For events that are expected to happen less than once per year per unit of exposure, the likelihood of the risk event happening in a year for a Tranche and the frequency of the risk event happening are equivalent (e.g., a 100-year flood has an annual probability, or LoRE, of 0.01, and the expected number of floods per year, Frequency, is 0.01). For risk events that are expected to happen more often than once per year per unit of exposure, the likelihood of the risk event is 1 though the frequency of the risk event is greater than 1. Frequency captures the difference between a risk event that happens twice per year and 1,000 times per year, whereas likelihood, as a metric, is unable to do so given a one-year time period for analysis.[51]

e. Test Year Baseline Risk Value

Throughout this RAMP report, all Bow Ties show the Test Year (TY) Baseline Risk Values for 2027—the TY for PG&E's next General Rate Case (GRC). Test-Year Baseline Risk Values for 2027 are calculated based on Frequency and Consequence of the Risk Event and may be adjusted for estimated increases due to factors such as climate change

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51 A potential approach to this issue would be to vary the period for analysis (i.e., a month, a day) in order to compute a LoRE < 1. However, PG&E believes that varying the analysis period from a year would add complexity without substantial benefit, especially since PG&E's enterprise risks have frequencies ranging in order of magnitude from 10^{-3} to 10^4.

and cyber-attacks and adjusted for estimated reductions in Frequency and Consequence due to the effectiveness of mitigations that are implemented prior to the start of 2027 GRC period.

2. Modeling the Cross-Cutting Factors

Cross-cutting factors are risks that impact the likelihood or consequence of multiple Risk Events on PG&E's CRR. PG&E uses an approach consistent with the 2020 RAMP implementation of CCFs. PG&E integrates each applicable cross-cutting factor into the appropriate RAMP risk models as a driver, driver component or consequence of that specific risk.

There are five ways the cross-cutting factors are included in the event-based risk models.

a) Driver: Appears on the left-hand side of the Bow Tie as a driver and is modeled identically to other drivers. Frequency of a Risk Event associated with cross-cutting drivers is identified in the same manner as for the other drivers based on historical frequency of those events, stand-alone modeling, or SME judgement if historical or modeled data is not available or not fit for purpose in the model.

b) Consequence Multiplier: When a cross-cutting factor affects a consequence of an event for an Outcome regardless of drivers, it is modeled as a Consequence Multiplier to the Natural Unit of the simulated risk event outcome, affecting the CoRE.

c) Outcome: Where the impact of a cross-cutting driver differs from the impact of the non-cross cutting drivers on the consequences of a Risk Event (e.g., the severe Seismic outcome is driven solely by the Seismic driver).

d) Escalating Frequency: Is applied as a Frequency Multiplier over time to one or more applicable risk drivers (e.g., increasing natural hazard risk due to climate change).

e) Embedded: The impact of the CCF is already accounted for in the assessment of frequency and consequence of a risk event as a control.

More details on Cross Cutting Factors and their modeling are provided in Exhibit (PG&E-2), Chapter 3, Section C.

3. Modeling the Mitigations and Control Programs

A mitigation is commonly defined as a measure or activity proposed or in process that is designed to reduce the impact/consequences and/or the likelihood/probability of a risk event for a specific period of time. The adequacy and effectiveness of a mitigation is assessed based on how much of the exposure is affected (i.e., scope of mitigation), the impact on specific driver/sub-driver frequencies (and how those frequencies may change over time), the impact on the consequence of specific attributes, and the associated cost.

A control is a currently established measure that modifies risk, such as standard operation/routine work that is undertaken as part of normal business operations and is not a new program, or an enhancement to an existing one.[52] Controls have no end date.

The benefits of applying mitigations and controls are represented by percentage reductions in driver/sub-driver frequencies by tranche and outcome, and/or consequence magnitude (e.g., the number of CMI per risk event outcome as simulated) by tranche and outcome. Mitigations are further defined by the duration of risk reduction benefits once mitigation is complete, and effectiveness degradation with time.

PG&E developed workpapers (WP) featuring all relevant values that characterize mitigation and control programs for each Risk Event, including the effectiveness of each mitigation by driver or outcome, justification for that effectiveness, the mitigation benefit length and the justification for the benefit length. The mitigation effectiveness WPs are included as part of the modeling WPs for each RAMP risk.[53]

4. Cost-Benefit Ratio

CBR is a metric for representing the benefit to cost ratio of a mitigation, where benefit is described in terms of risk reduction. The RDF Proceeding Phase II Decision states that “The Cost-Benefit Ratio calculation should be calculated by dividing the dollar value of Mitigation Benefit by the Mitigation

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[52] D.22-12-027, Appendix A, p. A-3.

[53] The workpaper is number 3 in each set (e.g., for the LOC on Gas Transmission Pipeline risk, abbreviated as LOCTM, the workpaper is identified as GO-LOCTM-03)

cost estimate."[54] Further, "[t]he values in the numerator and denominator should be present values [and, f]or capital programs, the [mitigation] costs in the denominator should include incremental expenses made necessary by the capital investment."[55]

PG&E's CBR results shows the risk reduction achieved per 1 million dollars of cost. For example, a risk event with Frequency of one event per year and Consequence of 10 million CMI has a risk value of $31.7 million risk-adjusted.[56] If a mitigation that costs $10 million reduces the Frequency of this risk event by 50 percent (from 1 event per year to 0.5 events per year), then then risk reduction (the difference between pre- and post-mitigation value) is 15.85 and CBR is 1.585.[57]

When the benefit of a mitigation lasts more than one year, risk reduction is aggregated by the present value of risk reduction over the benefit years. Equation 2 shows the CBR calculation:

$$CBR = "NPV(Risk\ Reduction\ Values)\ "\ /"NPV(Program\ Costs)"$$

Where:

- Net Present Value (NPV) (Risk Reduction Values) and NPV (Program Costs) are the NPV of the Risk Value and Program Costs.

The following sections discuss how PG&E has implemented the RDF Proceeding Phase II Decision requirements for calculating CBRs.

a. Discounting

As noted above, in compliance with the RDF Proceeding Phase II Decision, PG&E shows the numerator and denominator of the CBR as present values.[58] PG&E uses a single discount rate, its After Tax Weighted Average Cost of Capital (ATWACC) to calculate the present

54 D.22-12-027, Appendix A, p. A-15, No. 25.

55 D.22-12-027, Appendix A, p. A-15, No. 25.

56 Risk Value = Frequency x CoRE = Frequency (1) * 10 * 3.17 = 31.7.

57 Risk Reduction = Pre-mitigation Risk Value (31.7) x Effectiveness (50%) = 15.85.
CBR= Risk Reduction / Cost = 15.85/ 10M = 1.585 /$M spend.

58 D.22-12-027, Appendix A, p. A-15, No. 25.

value of all future costs and attributes. The base year for all discounting is 2023.[59]

PG&E focused on two core principles when discounting:

1) Costs and benefits occurring over different time periods should be assessed on an equal basis. Principle 1 implies a non-zero discount rate for costs to account for the time value of money.
2) All else being equal, CBRs should not change if both costs and mitigations are offset by the same period of time.[60]

To achieve Principle 2, the discount rate for Attributes (i.e., in the numerator of the CBR) must not only be the same across all Attributes but also must be the same as the discount rate for costs (i.e., the denominator).

The PG&E's ATWACC is derived as 6.7 percent as in Table 2-14 but, for the purpose of the CBR calculation, PG&E rounds the cost of capital to the nearest 50 basis points (or 0.5 percent) because the exact ATWACC is uncertain and keeping the discount rates somewhat consistent over several years would make the analysis of a particular program or projects not change just due to the discount rate.

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59 The RDF Proceeding Phase II Decision requires IOUs to apply the DOT VSL adjusted to the *base year* of their respective RAMP filing, which the California Public Utilities Commission (CPUC) defines as the last year of recorded costs. See Maryam Ghadessi, CPUC, Policy and Planning Division, Utility General Rate Case – A Manual for Regulatory Analysts (Nov. 13, 2017), available at: <https://www.cpuc.ca.gov/-/media/cpuc-website/files/uploadedfiles/cpuc_public_website/content/about_us/organization/divisions/policy_and_planning/ppd_work/ppd_work_products_-2014_forward-/ppd-general-rate-case-manual-1-.pdf> (accessed May 7, 2024).

60 As an example of why Principle 2 is necessary, consider a program that starts immediately and runs for a set number of years, with costs only incurred during that period. All else being equal, the program should have the same CBR if it started one year later, otherwise one could simply defer or expedite the work to increase the CBR score with no fundamental improvement in the program.

TABLE 2-14
2023 AFTER TAX WEIGHTED AVERAGE COST OF CAPITAL CALCULATION

Line No.	Component	Weight	Cost of Capital (%)	WACC		After Tax WACC
1	Debt	48%	4.3	2.1	x (1 - tax rate)	1.5
2	Common Stock	52%	10.0	5.2		5.2
3						6.7 Rounded to 7.0

Note: The ATWACC used in the risk model is based on PG&E's cost of capital authorized in D.22-12-031.

This discount rate was determined solely based on the principles and considerations above. Therefore, it is only valid in the context of calculating CBRs in this RAMP Report and should not be extended to other applications without further consideration.

To implement the principles for discounting above, PG&E multiplies the calculated benefits (i.e., the numerator) by the inflation rate (2.3 percent per annum) before discounting by the 7 percent. This is because in PG&E's risk models, benefits are stated in base year (2023) dollars and must be adjusted to nominal dollars (i.e., adjusted for inflation), as the ATWACC is a nominal rate. This is equivalent to discounting the calculated benefits by real discount rate (i.e., inflation-adjusted discount rate of 1.07/1.023-1=4.59%). Costs (i.e., the denominator) are already forecasted in nominal dollars and do not need any adjustment in the discount rate of 7 percent.

b. Mitigation and Control Program Mitigation Costs

The basis of the program costs used to calculate the CBR are high-level capital and expense cost estimates at this time. PG&E used the best available information when calculating and estimating the costs associated with each mitigation.[61] These costs are included in the WPs supporting this RAMP report.[62]

Because PG&E's GRC forecasting process is still in the early stages, the mitigation forecast costs to be included in the 2027 GRC may be different from the estimates included in this RAMP Report, including potential changes because of SPD and intervenor feedback in this proceeding.

c. Treatment of Capital Costs

To account for the incremental expenses associated with the capital investments such as depreciation and return on equity over the book life of an asset, PG&E is using an estimated Revenue Requirement associated with capital spend. Using the Revenue Requirement to calculate NPV allows for a direct comparison between the CBRs for capital programs and the CBRs for expense programs by normalizing the risk reduction per dollar spent.[63] The CBRs presented in this RAMP Report include a Present Value of Revenue Requirements factor to convert capital dollars to NPV of a revenue requirement for each capital investment subject to cost-of-service ratemaking.

d. Pre-Mitigation and Post-Mitigation Risk Values

Pursuant to the RDF Proceeding Phase II Decision, PG&E calculated pre- and post-mitigation risk values for each year that proposed mitigations are in effect.[64]

For this 2024 RAMP, PG&E defines the different periods as:

- <u>Pre-mitigation</u>: For programs planned for the GRC period (2027-2030) PG&E calculates a pre-mitigation program value that accounts for the benefits from any mitigations that are planned for 2024–2026;

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61 As discussed in the Introduction to this Report (Exhibit (PG&E-1), Ch. 1, Section D.3), these estimates are preliminary and subject to change in the 2027 GRC application.

62 Each RAMP risk chapter (in Exhibits (PG&E-3 through PG&E-7)) and the Cross-Cutting Factor chapter (Exhibit (PG&E-2), Ch. 3) includes cost tables and supporting financial workpapers that show the costs from 2024 through 2030 used to develop the CBR.

63 A.20-06-012, Attachment A, RAMP Report, p. 3-27, lines 8-19.

64 D.22-12-027, Appendix A, p. A-13, No. 13.

- 2027 TY Baseline: PG&E's upcoming GRC TY; and
- Post-Mitigation: The benefits from proposed mitigations for the 2027-2030 GRC period are accounted for in the Post-mitigation Risk Values.

e. Risk Reduction

The Risk Reduction Value captures all the program's benefits and is not limited by the GRC time period. For example, gas transmission pipeline replacement assumes a capital life of 100 years so the benefits are assumed to accrue over all 100 years.

Certain programs in this RAMP Report address multiple risks. For example: (1) System Hardening [Undergrounding] program reduce the risk of both the Wildfire risk and the Failure of Distribution Overhead Asset Failure risk; and (2) Locate and Mark – Distribution program reduces risk of Loss of Containment on Gas Distribution Main or Services, Failure of Electric Distribution Underground Assets, and Public Contact with Intact Energized Electrical Equipment.

For mitigations that address multiple risks, risk reduction from all applicable risk events is factored into the program Risk Reduction (the numerator of the CBR calculation). A program affecting multiple risk events will show up in multiple RAMP Risk Chapters.

Many of the cross-cutting mitigations (mitigations aligned to the cross-cutting factors) address multiple RAMP risk events. The Risk Reduction for these mitigations is calculated at the risk level and then summed across each risk. The risk reduction is presented at the cross-cutting factor level (e.g., a Risk Reduction score is provided for all Records and Information Management mitigations combined) and then allocated to each RAMP risk the cross-cutting factor impacts.

Some mitigations presented in this report also address additional PG&E risks on PG&E's Enterprise Risk Register but not included in this RAMP Report. This is especially true for cross-cutting risk reduction programs. PG&E considers these mitigations' risk reduction value for the RAMP risks only, so CBRs will not be reflective of the complete risk reduction benefits offered by those programs.

f. Tranche-Level CBR

The RDF Proceeding Phase II Decision states that Utilities should provide CBRs at the tranche level. PG&E provides CBRs at the tranche level for each risk in supporting WPs.[65]

To calculate tranche-level CBRs, the risk model requires a tranche-level cost estimate for each mitigation and control.[66] This approach is consistent with the RDF, which requires CBRs to reflect the full set of benefits that result from the incurred costs.[67]

Many of the cross-cutting mitigations address multiple RAMP risk events, but the costs cannot be meaningfully separated or allocated. Therefore, the CBRs for the cross-cutting mitigations are provided at the cross-cutting factor level (i.e., CBRs for cross-cutting programs are not provided at the risk-tranche level, just at the risk level).

g. Foundational Activities

In D.21-11-009, the Commission addressed treatment of foundational activities in RAMP. The Commission defines foundational programs and/or activities as "initiatives that support or enable two or more mitigation programs or two or more risks but do not directly reduce the consequences or the likelihood of risk events."[68] Pursuant to that Decision, the Commission requires IOUs to include forecast costs of foundational activities in the CBR calculations for the control and mitigation programs that the foundational activities enable, subject to minimum cost thresholds.[69]

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65 See Exhibit (PG&E-2), WP RM-RMCBR-16.

66 The modeling workpapers with index number 3 (e.g., WP EO-DOVHD-3, WP GO-LOCTM-3) for each Exhibit/Chapter include a table specifying how program costs are allocated by tranche.

67 D.22-12-027, Appendix A, p. A-15, No. 25.

68 D.21-11-009, p. 19.

69 D.21-11-009, p. 141, OP 1(e) and (e)(i) requires the following: "Each IOU shall include the cost of foundational programs in their mitigation RSE calculations if the aggregate cost over the upcoming GRC funding period of the foundational programs supporting a portfolio of risk mitigations exceeds the following: For PG&E and SCE, the lesser of $10 million, or 20 percent of the cost of the portfolio of enabled mitigations, subject to a minimum of $5 million for the percentage test."

Because foundational activities enable multiple control and mitigation programs, PG&E allocated the foundational activity costs to the enabled mitigation or control programs proportional to the cost of the enabled programs. Individual RAMP risk chapters provide information on foundational activities applicable to the specific risk event including, but not limited to, foundational activities that exceed the cost threshold for inclusion in CBR calculations.

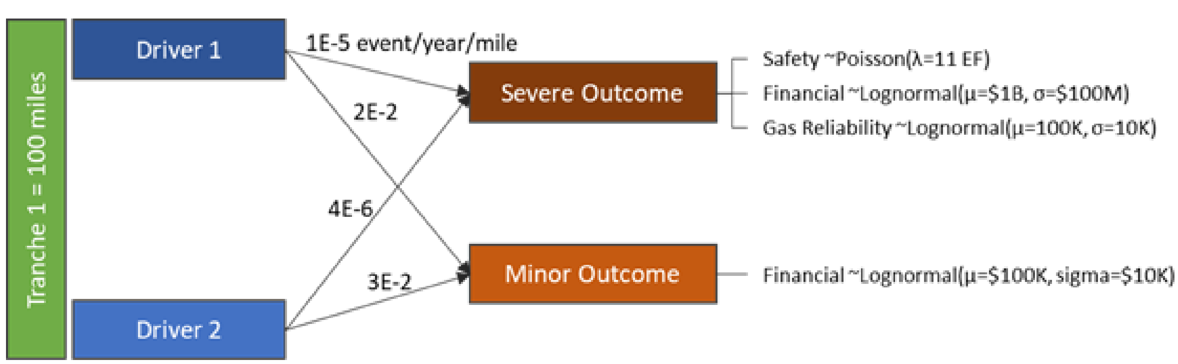
5. Risk Analysis Example: CBA, Risk Value, Risk Reduction, and CBR

This section walks through an example of how a simple Bow Tie model (shown in Figure 2-11 below) is used to compute CBR values for two proposed mitigations and addresses:

a) LoRE;
b) CoRE;
c) Expected Value from simulated CoRE;
d) Risk Value;
e) Risk Reduction; and
f) CBR.

The calculations presented in this section are also included in Exhibit (PG&E-2), WP RM-RMCBR-16.

FIGURE 2-10
EXAMPLE BOW TIE INPUT ASSUMPTIONS



Note: Poisson and Lognormal refer to the parametric probability distributions used to model the outcome consequences of the risk event.

The example Bow Tie in Figure 2-10 includes:

- Two drivers – Driver 1 and Driver 2;

- Two Outcomes – Minor and Severe;
- One tranche, Tranche 1, defined by an exposure of 100 miles of an asset;
- The risk event is characterized by potential Safety, Gas Reliability, and Financial consequences;
- The Minor outcome has only Financial consequences; and
- The Severe outcome has greater Financial consequences, as well as Safety and Reliability impacts.

The two distinct outcomes for this single risk event allow the model to capture the low frequency high consequence outcome and the high frequency low consequence outcome, each of which have uncertainty regarding the magnitude of the consequences.

a. Likelihood of Risk Event

Likelihood of Risk Event is calculated per tranche-outcome-(sub)driver.[70] The example Bow Tie in Figure 2-8, with one tranche, two drivers, and two Outcomes requires (1*2*2 = 4) four frequency values.

Where there is more than one tranche, PG&E calculates as many sets of tranche-driver-outcome frequencies and Outcome Attribute distributions as there are tranches.[71] Risk Events that are presented in this RAMP report include tens, hundreds or thousands of LoRE values per Risk Event.

For the sample Bow Tie shown in Figure 2-11, the aggregated LoRE is the sum of the four LoRE shown in the Aggregated Outcome column of Line No. 3, Table 2-15.

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70 The Likelihood of Risk Event is in fact specified at the tranche-outcome-subdriver level. In the example, driver and sub-driver are used interchangeably.

71 The Risk Model Input File (modeling workpaper with index 1, e.g., WP EO-DUNGD-1) and TY Baseline Risk Data (modeling workpaper with index 5, e.g., WP EO-DUNGD-5) for each risk event contains tables with LoRE values for all tranche / sub-driver / outcome combinations.

TABLE 2-15
SAMPLE BOW TIE: SUMMARY OF LORE BY DRIVER, OUTCOME, AND RISK EVENT

Line No.	Calculation	Minor Outcome	Severe Outcome	Aggregated Outcome	Percent of Frequency by Driver
1	LoRE for Driver 1	0.02	1.0E-05	0.02001	40%
2	LoRE for Driver 2	0.03	4.0E-06	0.030004	60%
3	LoRE (#/year/mile)	0.05	1.4E-05	0.050014	
4	Freq (#/year)	5	0.0014	5.0014	
5	% of Freq	99.97%	0.03%		

- LoRE for each Driver = Minor Outcome + Severe Outcome;
- LoRE for all Drivers = LoRE for Driver 1 + LoRE for Driver 2;
- Frequency (number of events per year) = LoRE (freq of events per mile per year) x 100 (exposure);[72] and,
- Percent of Frequency = Frequency of Each Outcome / Total Frequency – For example, 5/(5+0.0014) = 99.97%

Therefore, the model expects 0.050014 events per year per mile, which is equivalent to a probability of 0.050014 that the event will happen each year on a given mile of exposure.

Given 100 miles of exposure on the tranche, the risk event frequency is:

Frequency = Exposure x LoRE = 100 x 0.050014 = 5.0014 events per year

Of these 5.0014 events:

- 99.97% of the time the outcome is Minor; and
- 0.03% of the time (1 in 714 years) the outcome is Severe.

b. CoRE for one Trial

Risk event consequences are calculated per tranche-outcome-attribute combination. The Severe Outcome is illustrated in this example given its complexity relative to the Minor Outcome.

The Severe Outcome has Safety, Reliability, and Financial attributes, each defined using a parametric probability distribution

72 The value “100” is used here because the Tranche is defined as 100 miles and the LoRE is measured per mile.

(two Lognormal, one Poisson). This example of the CoRE calculation using the CBA assumes that these attributes are deterministic (i.e., the model does not include uncertainty about the attribute value) to simplify the application of the CBA. A description of the probabilistic case (i.e., a model that includes elements of uncertainty in the attribute value) follows in Section D.5.c, CoRE as Expected Value.

The Consequences of a Risk Event in Natural Units for the Severe Outcome are listed in Column A of Table 2-16. The step-by-step calculation below computes all quantities for the Safety Attribute to illustrate the Safety CoRE calculation. Identical steps are performed for each other Attributes.

TABLE 2-16
SAMPLE BOW TIE: DATA FOR SEVERE OUTCOME
ASSUMING DETERMINISTIC CONSEQUENCE

		A	B	C	D
Line No.	Attribute	Consequence of Risk Event in Natural Unit	Monetization Factor	Risk Adj. Attribute CoRE	Risk Adjustment Factor
1	Safety	11 EF	$15.23M/EF	404	2.41
2	Gas Reliability	100K Customers	$1570/cust.	302	1.93
3	Financial	$1B	1	1,990	1.99

Calculating the Safety CoRE

Column A has values in Natural Units for each Attribute. The expected values of the distributions are assumed to be a deterministic consequence. The Safety consequence is 11 EFs.

Column B has the monetization factor, expressed in $2023, for each Attribute. For the Safety attribute, that factor is $15.23 million/EF.

Column C has the Risk Adjusted Attribute CoRE value. This is calculated by applying the Risk Attitude Function (RAF) to the monetized attribute value, computed as Col A x Col B. For the Safety attribute, the break points to divide the three regions are 1 EF and 10 EF, or, $15.23M and $152.3M. Since the consequence here is 11 EF, the impact falls in the catastrophic region of the RAF (see Section C.6.b). The Risk-adjusted Safety CoRE, then, is computed as follows:

$$\text{Risk Adjusted Safety CoRE} = 152.3 \times 2 - 15.23 \times 1 + (167.53 - 152.3) \times 7.5$$
$$= 403.6$$

Column D has the Risk Attitude Factor, which is determined by both the Attribute and the Natural Unit value (col A). This is the ratio of the Risk Adjusted Attribute CoRE to the Monetized Attribute Level.

Following the same steps, noting that the Minor Outcome consequences are in Routine Region of the RAF, the CoRE of the Minor Outcome is 0.1.

c. CoRE as Expected Value

PG&E's risk model simulates the Natural Units for relevant tranche-outcome-attribute combinations. Table 2-17 below shows the simulated natural unit values for all Severe Outcome attributes for 10 trials,[73] based on the calculations described in Section D.5.b above.

[73] PG&E's model runs 10,000 trials per distribution.

TABLE 2-17
SAMPLE BOW TIE: SIMULATED SEVERE OUTCOMES VALUES IN NATURAL UNITS AND ATTRIBUTE CORE CALCULATIONS[(a)]

	Safety				Reliability				Financial			
Trial	Sim Natural Unit (EF)	Monetization Factor	CoRE ($M risk adj.)	Implied Risk Adj. Factor	Sim Natural Unit (1k Cust)	Monetization Factor	CoRE ($M risk adj.)	Risk Adj. Factor	Sim Natural Unit ($M)	Monetization Factor	CoRE ($M risk adj.)	Risk Adj. Factor
1	8	15.23	228	1.88	108	1570	329	1.93	999	1	1,988	1.99
2	14	15.23	746	3.50	92	1570	278	1.92	831	1	1,651	1.99
3	8	15.23	228	1.88	111	1570	337	1.93	959	1	1,908	1.99
4	5	15.23	137	1.80	104	1570	316	1.93	969	1	1,928	1.99
5	11	15.23	404	2.41	93	1570	279	1.92	1088	1	2,651	2.44
6	11	15.23	404	2.41	99	1570	298	1.92	1004	1	2,018	2.01
7	12	15.23	518	2.83	99	1570	300	1.92	989	1	1,968	1.99
8	11	15.23	404	2.41	101	1570	307	1.93	818	1	1,627	1.99
9	9	15.23	259	1.89	102	1570	310	1.93	1192	1	3,431	2.88
10	12	15.23	518	2.83	100	1570	303	1.93	1116	1	2,860	2.56
	Safety CoRE 475				Reliability CoRE 302				Financial CoRE 2,208			
Sum of Attribute Values: 2,985												

(a) The Attribute CoRE is the average of the CoRE per trial for that Attribute.

The additional step required to compute the Attribute CoRE (compared to the steps required to calculate the CoRE for one trial described in Section D.5.b) is to take the average of all Trial CoRE values.

Therefore, the CoRE for the Severe Outcome is the average sum of the three Attribute CoRE values: 475 + 302 + 2,208 = 2,985.

Following the identical process, PG&E calculated the CoRE for the Minor Outcome (based only on the Financial Attribute because it is the only outcome of a minor event). The Minor Outcome CoRE is 0.10.

TABLE 2-18
SAMPLE BOW TIE: CORE PER OUTCOME

Line No.	Outcome	CoRE
1	Severe	2,985
2	Minor	0.10

Using these outcome-based CoRE values, the CoRE at the risk-level can be calculated as a weighted sum of CoRE based on the frequency percentage of each outcome.

CoRE = % Freq (Minor Outcome) x CoRE (Minor Outcome)
+ % Freq (Severe Outcome) x CoRE (Severe Outcome)

CoRE = 0.03% (Table 2-15) x 2,985 (Table 2-18) + 99.97% (Table 2-15) x 0.10 (Table 2-18) = 0.94

d. Risk Value

The Risk Value is computed at the tranche-outcome level. Given a single tranche for this example risk, the risk values per outcome are:

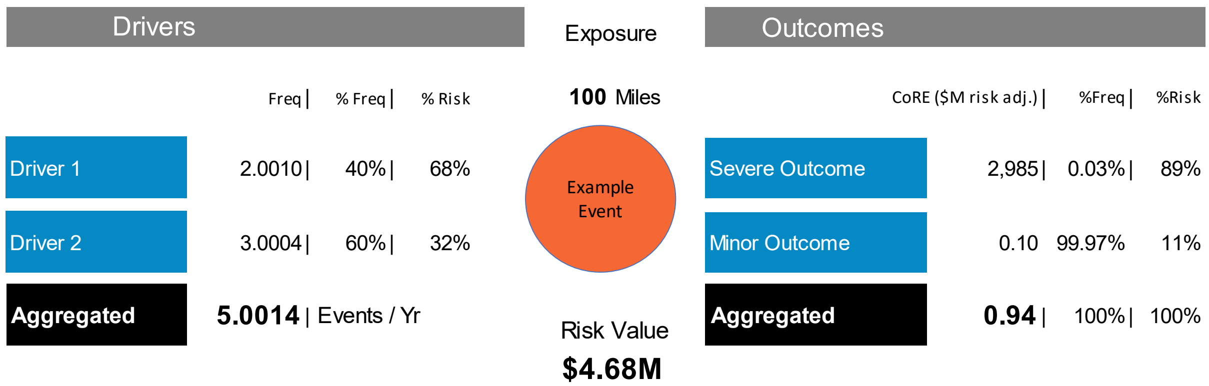
Risk Value (Minor Outcome) = Frequency (Minor Outcome) x CoRE (Minor Outcome)
= 5 (Table 2-15) x 0.10 (Table 2-18) = 0.50

Risk Value (Severe Outcome) = Frequency (Severe Outcome) x CoRE (Severe Outcome)
= 0.0014 (Table 2-15) x 2,985 (Table 2-18) = 4.18

Risk Value = Risk Value (Minor Outcome) + Risk Value (Severe Outcome)
= 0.50 + 4.18 = 4.68
Note that this is equivalent to multiplying the aggregate frequency by the aggregate CoRE (using expanded precision):
= 5.0014 x 0.9355 = 4.68

The sample risk Bow Tie, Figure 2-11 below, shows that the Severe Outcome contributes 89 percent of the total risk though it represents only 0.03 percent of the frequency of a risk event.

FIGURE 2-11
SAMPLE BOW TIE: EXAMPLE RISK EVENT SUMMARY



e. Risk Reduction Value

To calculate the Risk Reduction values PG&E outlines the effectiveness of the proposed mitigation and the duration of the mitigation benefit.

Table 2-19 is information for two mitigations used in the example calculation.

TABLE 2-19
SAMPLE BOW TIE: CHARACTERISTICS FOR MITIGATION 1 AND MITIGATION 2

Line No.	Mitigation	Target	Effectiveness percentage	Scope	Benefit Duration	Effectiveness Degradation
1	M1	Frequency of Drivers 1 and 2	20%	17 miles in Year 1	4 Years	10% annually
2	M2	Safety Consequences of Severe Outcome	20%	100 miles each year from Year 1 to Year 4	1 Year	0%

1) Mitigation 1 – Program Frequency

Proposed mitigation M1 targets all risk drivers for the risk event and is 20 percent effective at reducing event frequency. Effectiveness of M1 is provided per unit of exposure to which the mitigation is applied. Using the scope and effectiveness of the mitigations, the model calculates the average effectiveness at the tranche level:

Average effectiveness = Effectiveness x Scope / Tranche Exposure
= 20% x 17 miles/ 100 miles
= 3.4%

Because M1 affects all risk drivers equally applied to the single risk tranche, Risk Reduction is equal to 3.4% of the Risk Value (4.68 x 0.034 = 0.16).

Note that this calculation is equivalent to computing Risk Reduction as:

Pre-Mitigation Risk Value = 4.68 (Section D.5.d)
Post-Mitigation Risk Value = (1 - 3.4%) x 4.68 = 4.52
Risk Reduction Value (M1) = Pre-Mitigation Risk Value – Post-Mitigation Risk Value
= 4.68 - 4.52 = 0.16

2) Mitigation 2 – Consequence Mitigation

Proposed mitigation M2 reduces the magnitude of the Safety consequence by 20 percent, but only for the Severe Outcome. The mitigation effectiveness is applied to the entire project scope, so the average effectiveness at a tranche level is the same as the effectiveness at a program exposure level:

Average effectiveness = Effectiveness x Scope / Tranche Exposure
= 20% x 100 miles / 100 miles = 20%

The average effectiveness applies to the Safety CoRE only when computing the change in CoRE.

CoRE reduction = Effectiveness x Safety CoRE
= 20% x 475 (Table 2-17) = 95

This aggregate CoRE reduction for the Severe Outcome is equivalent to a 3.18 percent overall effectiveness (95 / 2,985). Therefore, the risk reduction is equivalent to 3.18 percent of the Risk

Value for the Severe Outcome (4.18 x 0.0318 = 0.13). Note that this calculation of Risk Reduction is equivalent to the following:

Pre-Mitigation Risk Value = 4.68 (Section D.5.d)

Post-Mitigation CoRE (Severe Outcome) =
(1-20%)*475 (Table 2-17) + 302 (Table 2-17) + 2,208 (Table 2-17) = 2,890

Post-Mitigation Risk Value (Severe Outcome)
= Frequency (Severe Outcome) x Post-Mitigation CoRE (Severe Outcome)
= 0.0014 (Table 2-15) x 2,890 = 4.05

Post-Mitigation Risk Value (Severe Outcome) + Post-Mitigation Risk Value (Minor Outcome)
= 4.05 + 0.50 (Section D.5.d) = 4.55

Risk Reduction Value (M2)
= Pre-Mitigation Risk Value - Post-Mitigation Risk Value
= 4.68 – 4.55 = 0.13

TABLE 2-20
SAMPLE BOW TIE: RISK REDUCTION VALUE BY MITIGATION

Line No.	Mitigation	Risk Reduction Value
1	M1	0.16
2	M2	0.13

f. CBR

CBR (Equation 2) is the risk reduction per dollar spent:

$$CBR = "NPV(Risk\ Reduction\ Values)\ " / "NPV(Program\ Costs)"$$

PG&E calculated the CBRs shown in Table 2-21 for the two sample mitigations using: the risk reduction values in Table 2-20; the discounting factor discussed in Section C.4.a to calculate the NPV; and sample program costs. Program M1 has an initial capital cost of $2 million with PVRR Multiplier of 1.5, with benefits lasting four years and Program M2 has ongoing expense costs of $0.5 million per year.

Further, the benefits of Program M1 degrade somewhat over time, so the benefits decrease with time.

TABLE 2-21
SAMPLE BOW TIE: RISK REDUCTION VALUE BY MITIGATION

Line No.	Risk Reduction Value and Cost by Mitigation	Year 1	Year 2	Year 3	Year 4	NPV
1	Risk Reduction Value (M1)	0.16	0.14	0.13	0.11	0.49
2	Risk Reduction Value (M2)	0.13	0.13	0.13	0.13	0.48
3	M1 Program Cost ($M – Capital)	$2.00	–	–	–	3.00
4	M2 Program Cost ($M – Expense)	$0.50	$0.50	$0.50	$0.50	1.81

$$\text{CBR (M1)} \quad = \quad \text{NPV of Risk Reduction Value (M1) / NPV of Program Costs (M1)}$$
$$= \quad 0.49 / [2.00 \text{ x } 1.5] = 0.49 / 3 = 0.16$$
$$\text{CBR (M2)} \quad = \quad \text{NPV of Risk Reduction Value (M2) / NPV of Program Costs (M2)}$$
$$= \quad 0.48 / 1.81 = 0.27$$

E. Workpapers Supporting PG&E's RAMP Risk Models

The RDF Proceeding Phase II Decision requires that PG&E provide in its RAMP Report a ranking of all RAMP mitigations by CBR.[74] This ranking is provided in Exhibit (PG&E-2), WP RM-RMCBR-15.

A list of the 12 RAMP risks with the final safety risk value and final total risk value for each is also included in Exhibit (PG&E-2), WP RM-RMCBR-14.

PG&E has developed WPs supporting each of its 12 RAMP risk models and their mitigation and control CBRs along with Model User Guides. The WPs for each risk chapter consist of the following files.

- Source Documents Index (FA-RiskID)[75] and Source Documents – The source documents index lists all of the files used in the risk model. It includes a reference to the source file that is available in soft copy and/or a link to publicly available information. The index number for each file listed

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74 D.22-12-027, Appendix A, p. A-16, No. 26.

75 FA is Functional Area such as EO, GO, SS, GEN, EHS and IT. RiskID is five-letter ID of each risk such as WLDFR, DOVHD, LOCTM, etc.

on the source document index is also used in the risk model to reference the data used in the model.

- Risk Model Input Files (FA-RiskID-1) – This file includes the inputs into the risk model for each of the 12 RAMP risks. It lists the drivers, sub-drivers, tranches, and consequences for each risk. Modeling information includes frequency inputs by sub-driver, frequency multipliers, consequence multipliers, mitigation exposures, mitigation costs, mitigation effectiveness on consequences and frequencies, and their escalation methods.
- Bow Tie File (FA-RiskID-2) – This file includes the outputs from the risk model for each of PG&E's RAMP risks. It includes the Bow Tie and Consequence Table graphics included in each RAMP risk chapter (Exhibit (PG&E-3) through Exhibit (PG&E-7)). In addition, the file includes detailed output for driver frequency, outcome frequency, tranche level exposure, risk value by outcome, risk value by tranche, risk value by outcome by attribute, and driver contribution to risk values.
- CBR File (FA-RiskID-3) – This file includes mitigation and control program data including the effectiveness of each program, the justification for the effectiveness percentage, the mitigation benefit duration, and reason for selecting that duration, and the annual degradation rate of effectiveness.

F. Addressing Stakeholder Feedback

PG&E presented its CBA implementation at a public workshop hosted by the SPD on April 11, 2024, as directed by D.22-12-027, OP 3.[76] Feedback was received from The Utility Reform Network (TURN), California Public Advocates (Cal PA), Mussey Grade Road Alliance (MGRA) and SPD. This section addresses modeling-related concerns raised by the parties and provides additional clarification to answers provided at the session.[77]

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76 CPUC, PG&E 2024 RAMP [Pre filing] Workshop #2: Cost-Benefit Approach Demonstration (Apr. 11, 2024), available at: <https://youtu.be/ehbPkwe2zlA?si=mj6rL6x5n7FpqBE7> (accessed May 7, 2024).

77 Input provided by stakeholders at PG&E's pre-RAMP workshop, where its Risk Selection Process for RAMP was presented, is discussed separately in Exhibit (PG&E-2), Ch. 4, RAMP Risk Selection.

1. Adopting Granular ICE Calculator Values

During PG&E's presentation on the value of Electric Reliability, members of the SPD inquired about why PG&E elected to use the system-wide average value ($3.17/CMI) when the ICE calculator could ostensibly be used at a finer level of locational detail. For example, when assessing Wildfire risks and mitigations, PG&E has individual customer information at the segment level. This could be input into the ICE Calculator to develop Tranche-specific values of Electric Reliability.

Upon consideration, PG&E has chosen to continue using the system average Reliability values instead of more locationally or Tranche specific values. The reasons are three-fold:

- The current version of ICE (1.0) was released in 2016 and contains assumptions that are likely dated, as some of the surveys that were used to develop the model are more than 20 years old. For example, it currently assumes that backup generation is not a statistically significant factor in the determination of the value of Reliability for Residential and Medium and Large Commercial & Industrial customers. More generally, the relationship between underlying variables and Reliability value as represented by the ICE regression equations might require updating with a new set of regression equations (with new explanatory variables) to reflect changes over the decades since some the initial surveys were conducted. In D.22-12-07, the Commission authorized the IOUs to participate in Lawrence Berkeley National Labs' ICE 2.0 update. This effort is anticipated to be completed no earlier than the latter half of 2024. In the meantime, PG&E considers it premature to analyze risk and assess the value of long-term mitigations at a granular level using the dated customer information in the current version of the ICE Calculator.
- While it might be straightforward to input the number of Residential, Small, Medium and Large Commercial & Industrial customers in each circuit segment and/or Tranche, it is not clear what to assume for other explanatory variables that the ICE Calculator requires, and which granularity of each variable is appropriate. Just updating the proportion of Residential, Small, Medium and Large Commercial & Industrial

customers without updating other explanatory variable values at the granular level could result in distortion of results unless other variables are also updated at the same granularity. Of note, a significant contributor to the Calculator's value of Reliability for Residential customers is household income. All else being equal, higher household incomes lead to higher values of Reliability, higher Risk values and higher CBRs. The converse holds true for lower household incomes. While PG&E can obtain finer-grained household income data (e.g., at the county-level) to derive Tranche-level incomes for use in the ICE calculator, the adoption of these values needs to be evaluated with respect to community impact. At the very least, the use of granular data for household incomes, as well all other explanatory variables required, should be explored in the Risk OIR first before adoption.

- PG&E already prioritizes some of its investments by customer types on a non-economic basis, and introducing Tranche-specific, economically-based values of Reliability from ICE could lead to unforeseen impacts. For example, in determining tranche-level impact of PSPS, customers that provide critical services like hospitals and fire stations were given a higher weighting than others based on a weighting scheme that balances myriad considerations which was comprehensively analyzed and reviewed by stakeholders. Introducing Tranche-specific Reliability values could upset this existing scheme, which could lead to results that are at odds with the priorities and considerations identified by stakeholders. Therefore, before adoption of Tranche-specific values, the Commission should consider in the Risk OIR how they may affect established policies and priorities.

2. Discounting Values to 2023 Instead of 2027

TURN pointed out that PG&E reports risk, and risk reduction benefits in 2023 dollars by discounting future values (e.g., for 2027, the Test Year for PG&E's upcoming GRC) back to 2023. PG&E would then inflate the 2023 dollars back to 2027 when discussing values pertaining to the GRC Test Year. TURN suggests reporting risk, and risk reduction benefits in 2027 dollars instead.

While TURN's suggestion is not without merit, PG&E believes that its current approach is more consistent with Commission guidance when taken as a whole. In D.22-12-027, regarding establishing the Value of Statistical Life (VSL), the Commission directed "the IOUs to apply the published DOT VSL as the standard value to express the Safety Attribute, *adjusted for the base year of their respective RAMP filings.*"[78] It would seem inconsistent to adopt the base year only for determining the Safety consequences without intending it to apply to all other results like overall Risk values and risk-reduction benefits. Furthermore, the Commission defined the "base year" to be "the last year of recorded costs."[79] Taken together, the guidance suggests that for RAMP, results should be reported in "base year" dollars, which in PG&E's case is 2023. Conversion between 2023 and 2027 dollars involves either inflating or discounting values, a straightforward matter of multiplication by known factors. Cost-Benefit ratios will remain the same regardless of whether 2023 or 2027 dollars are used because both numerator and denominator will be inflated or discounted by the same rate. In summary PG&E will maintain its current approach of using 2023 dollars as it is most consistent with Commission guidance and does not create any significant hindrances to analysis.

3. Risk Scaling

a. The Use of Risk Scaling to Account for Uncertainty

In the workshop, PG&E pointed out that it is common to classify uncertainty into different types. Indeed, the United States Nuclear Regulatory Commission (US NRC) categorizes uncertainty as either:[80]

- Aleatory – based on the randomness of the nature of the events or phenomena and that which cannot be reduced by increasing the analyst's knowledge of the systems being modeled (i.e., random uncertainty or stochastic uncertainty, "known unknowns").

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78 D.22-12-027, pp. 35-36 (emphasis added).

79 Maryam Ghadessi, CPUC, Policy and Planning Division, Utility General Rate Case – A Manual for Regulatory Analysts (Nov. 13, 2017), p. 8.

80 US NRC, Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decisionmaking, Final Report (Mar. 2017), NUREG-1855, Rev. 1, p. 5.

- Epistemic – Uncertainty related to the lack of knowledge (i.e., "unknown unknowns").

PG&E also asserted that in the RDF, Aleatory Uncertainty is accounted for by CBA Principle 4 – Risk Assessment, i.e., by using probability distributions and probabilistic methods, like Monte-Carlo simulation to represent the randomness of the events and calculate well known properties like expected values. However, PG&E mentioned that Epistemic Uncertainty is not captured by Principle 4 and is one reason for the necessity of risk-averse Risk Scaling Functions. Members of SPD wondered whether PG&E's probability distributions used in Principle 4 already account for Epistemic Risks and whether by introducing a risk-averse Risk Scaling function, PG&E is accounting for this uncertainty twice.

In response, PG&E's approach does not "double count" Epistemic Uncertainty. To develop the consequence probability distributions per Principle 4, PG&E relies on observed data and Subject Matter Experts (SME). Hence it incorporates the "known unknowns" but it is possible that, for example, SMEs attempt to account for Epistemic Uncertainty when estimating probability distribution parameters. However, as mentioned above, PG&E's Risk Scaling approach is to observe the risk premiums for similar products from independent sources, in essence, to determine if anything could have been missed in its modeling, i.e., the "unknown unknowns." If PG&E's internal modeling already sufficiently accounts for uncertainty, the market prices would not show any Risk Premium multipliers, i.e., the prices from market sources would match PG&E's Unscaled Expected Value. In that case the Risk Scaling Function would have its multipliers set to 1.0 (but no lower in order to prevent a risk-seeking attitude). This is currently not the case based on available market data, but PG&E's approach does not preclude the possibility.

b. Inappropriate Use of Market Prices

Both TURN and SPD raised the issue of whether insurance markets are an apt metaphor in this setting because individuals have options as to whether to pay insurance premiums or not, but they do not have a choice to opt out of the mitigations under consideration.

In reply, PG&E highlights that the goal of using market data is to create an objective assessment of risk. It is true that individual ratepayers do not have the ability to opt in or out of the safety programs under consideration; whether they are funded through rates or not are a matter for the GRC (and other) proceedings and considered in light of the entire record, including, but not limited to funding levels, acceptable risk tolerance, and overall priorities. Therefore, it is important that decision-makers have an objective and consistent assessment of risk and mitigations' cost-effectiveness. The Commission has adopted market-based approaches to determine fair value of projects in other proceedings before and the use of market data here is no different. For example, in D.16-09-007,[81] the Commission found that PG&E's Portfolio Adjusted Value, which includes a *Net Market Value* component, complied with D.13-10-040's[82] requirement for a *cost-effectiveness protocol* for energy storage projects. On the other hand, adopting a-priori (without consideration of independent assessments) risk-neutral, Unscaled Expected Values does not present a fair and balanced assessment of risk and cost-effectiveness, which PG&E has explained in considerable detail above, and also in Phase III of the Risk OIR[83].

c. PG&E's Risk Scaling Function Represents Customers' Interests

TURN stated that PG&E purchases insurance to protect its shareholders. In D.16-08-018,[84] the Commission decided that utility shareholders' financial interests should be excluded from the GRC and RAMP risk evaluation and risk mitigation considerations. From here,

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81 Application of Pacific Gas and Electric Company (U 39-E) for Authorization to Procure Energy Storage Systems during the 2016-2017 Biennial Procurement Period Pursuant to Decision 13-10-040.

82 Order Instituting Rulemaking Pursuant to Assembly Bill 2514 to Consider the Adoption of Procurement Targets for Viable and Cost-Effective Energy Storage System.

83 See R.20-07-013, PG&E Opening Comments on Workshop #4, Risk Scaling.

84 Interim Decision Adopting the Multi-Attribute Approach (or Utility Equivalent Features) and Directing Utilities to Take Steps Toward a More Uniform Risk Management Framework.

TURN reasons that using market prices introduces shareholder interests into risk evaluation and risk mitigation considerations.

PG&E pointed out earlier why use of market prices does not introduce shareholder interests (see Implementing CBA Principle 6 – Risk Adjusted Levels above), In short, the Commission has determined that insurance (and insurance-related products) are reasonable costs of doing business, thus should be overseen by itself and funded through the GRC. So, TURN's concern that they represent shareholder interests is unwarranted.

d. Efficacy of Using Market Prices

MGRA questioned whether markets can account for risk better than IOUs themselves, since IOUs presumably have more information about their service territories, assets and operating conditions. MGRA reasons that if market participants do not possess as much information and expertise as the IOUs, then the prices would not be an accurate reflection of risk.

PG&E cannot comment on the level of knowledge that market participants possess but notes they have access to at least as much information as regulators and intervenors do, from PG&E's RAMP, GRC and WMP filings. In certain areas, for example, with consequence modeling, the insurance industry possesses detailed data far beyond what IOUs have. Instead of assuming a fixed value per structure (as PG&E does), they have comprehensive knowledge (age, size, type of construction, etc.) of structures on record and can ascertain their replacement cost directly, because it is their business to do so. It is reasonable to assume that entities possessing such considerable resources and expertise would exercise diligence when committing substantial amounts of capital in a financial transaction. One must also keep in mind that the market transactions under consideration are discretionary and mutually acceptable. Buyers like PG&E are not at the mercy of the market; they can walk away from a transaction if it is too expensive. Likewise, if insurance or capital market participants are not comfortable assessing and assuming the risk, they can choose not to transact. Therefore, it is reasonable to assume that market transactions represent a fair assessment of risk. Furthermore, if IOUs like PG&E do possess superior knowledge, transactions would only occur when prices are advantageous to them (i.e., low, or fair relative to the true level of risk) which would lead to an underestimate of risk. However, this would not occur under PG&E's approach, because there is a floor value established by the Unscaled Expected Value.

e. Technical Concerns with Application of Market Prices

SPD staff mentioned that market products incorporate both likelihood and consequences, i.e., there seems to be some element of frequency of occurrences incorporated into prices of insurance and catastrophic bonds. However, PG&E only scales the consequences, and Staff wondered whether this is an appropriate application of market data.

PG&E responds that it is consistent with its understanding that the market products that it obtained prices for cover overall losses, not just the expected consequence of one event. However, the RDF representation of risk, LoRE x CoRE, is itself the expected value of overall losses[85] and this makes scaling only the consequences appropriate, as follows. Assuming, with no loss of generality, that the market price of risk is some multiple *m* of the Unscaled Risk value, i.e., Market Price = *m* x LoRE x Unscaled CoRE, which is what PG&E can observe from insurance and catastrophic bonds. Then it is straightforward to rewrite this as Market Price = LoRE x (*m* x UnScaled CoRE) = LoRE x Scaled CoRE, where the Scaling Function simply multiplies Attribute Levels (i.e., all the potential outcomes) by the Risk Premium Multiplier *m* observed from prices. While one can take the position that *m* should be incorporated into LoRE instead of CoRE, the RDF does not make any provision for a scaling function for LoRE. It is

85 Mathematically, the expected overall loss E[Loss], as covered by insurance and catastrophic bonds, can be expanded

E[Loss] = P(Event) x E[Loss | Event] + P(No Event) x E[Loss | No Event]

The last term on the right hand side is 0 (there is no loss if no event occurs), while the first term is the RDF's LoRE x CoRE, i.e.

E[Loss] = P(Event) x E[Loss | Event] = LoRE x CoRE also possible that since LoRE represents a probability, scaling it could result in a value over 100 percent. Hence PG&E's approach of applying the Risk Premium multipliers solely to the consequence distributions is reasonable and consistent with market products and the RDF.

4. Application of Cost Benefit Ratios

The Public Advocates Office at the California Public Utilities Commission provided feedback that it would like to see in RAMP how the CBRs resulting from PG&E's RDF implementation are used to select mitigations.

At PG&E, CBRs are one of the considerations that are used in assessing and selecting mitigations, consistent with Row 26 of the RDF, as stated below:

In the RAMP and GRC, the utility will clearly and transparently explain its rationale for selecting Mitigations for each risk and for its selection of its overall portfolio of Mitigations. The utility is not bound to select its Mitigation strategy based solely on the Cost-Benefit Ratios produced by the Cost-Benefit Approach.

Mitigation selection can be influenced by other factors including, but not limited to, funding, labor resources, technology, planning and construction lead time, compliance requirements, Risk Tolerance thresholds, operational and execution considerations, and modeling limitations and/or uncertainties affecting the analysis.[86]

When selecting mitigations, PG&E does not employ broad overreaching criteria, but considers all relevant factors on a case-by-case basis. In this RAMP, PG&E has provided the reasons why each mitigation was selected, as required by Row 26 above.

5. Negative Salvage Values and the Present Value of Revenue Requirements

In the workshop, SPD Staff inquired about whether and how PG&E accounts for Negative Salvage Values when it determines the Present Value of Revenue Requirements (PVRR) multipliers that are applied to the cost forecast for capital projects.

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[86] D.22-12-027, Appendix A, p. A-16, No. 26.

PG&E's tool that estimates the PVRR multipliers (see Exhibit (PG&E-2), WP RM-RMCBR-13) accounts for Net Salvage Values that may be negative, for example, when there are non-zero removal costs.

PACIFIC GAS AND ELECTRIC COMPANY

RISK ASSESSMENT AND MITIGATION PHASE

CHAPTER 3

CROSS-CUTTING FACTORS

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PACIFIC GAS AND ELECTRIC COMPANY
RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 3
CROSS-CUTTING FACTORS

A. Introduction

1. Identifying the 2024 Risk Assessment and Mitigation Phase Cross-Cutting Factors

The Cross-Cutting Factors (CCF) included in the Pacific Gas and Electric Company (PG&E or the Company) 2024 Risk Assessment and Mitigation Phase (RAMP) are those that appear on PG&E's Corporate Risk Register (CRR) and impact RAMP risks.[1] CCFs are CRR items that are either: (1) not risk events themselves, but impact either the likelihood or consequence of other items on the CRR; or (2) are risk events themselves and also impact either the likelihood or consequence of other items on the CRR. In the latter instance, risk definitions and models are scoped to ensure mutual exclusivity.

The seven CCFs PG&E is presenting in this report are:

1) Climate Change;
2) Cyber Attack;
3) Emergency Preparedness and Response (EP&R);
4) Information Technology (IT) Asset Failure;
5) Physical Attack;
6) Records and Information Management (RIM); and
7) Seismic.

CCFs can impact RAMP risks in several ways. A CCF can be a unique risk driver or a component of an existing driver, therefore impacting the likelihood of an event. It can also impact the consequence of an event, increasing the impact of potential outcomes. Below are some examples for different ways that CCFs impact RAMP risks.

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[1] In 2019, PG&E changed the name of its Enterprise Risk Register to the Corporate Risk Register.

- Unique Driver: The Physical Attack and Seismic CCFs are both unique drivers of the Large Uncontrolled Water Release (Dam Failure) risk. A dam failure risk event can occur because of a physical attack or a seismic event.
- Component of an Existing Driver: The RIM CCF may not cause risk events on its own but can contribute to a risk event and therefore be represented as a component of another driver. For example, the absence of important records and information or the inability to access that information quickly cannot cause a Loss of Containment on Gas Transmission Pipeline risk event on its own, but can contribute to the likelihood of this risk event occurring through either of two risk factors—Incorrect Operations or Coordination Failure—if information is not readily available. RIM is represented as a separate driver in the Loss of Containment on Gas Transmission Pipeline Risk Bow Tie for visibility but is essentially a component of the Incorrect Operations risk driver.
- Consequence: PG&E's planning for and response to emergencies, included in the EP&R CCF, impacts the consequence of a risk event. If a Loss of Containment on Gas Transmission Pipeline risk event occurred, a lack of effective EP&R could increase the consequence of the event.

2. Presenting the CCFs in the 2024 RAMP

The CCFs appear in several locations in the 2024 RAMP report.

- In this chapter (Exhibit (PG&E-2), Chapter 3), PG&E shows how the CCFs map to the 2024 RAMP risks (see Tables 3-1 and 3-2 below), describes each CCF in detail, explains how it impacts the 2024 RAMP risks, discusses any changes since the 2020 RAMP, describes the mitigations and controls planned for the 2024 through 2030 period, and if applicable, provides Cost-Benefit Ratios (CBR).
- In each of the 12 RAMP risk chapters (Exhibits (PG&E-3, -4, -5, and -7)) PG&E identifies the specific CCFs that impact the likelihood or consequence of the risk events covered by those chapters.

3. Changes Since the 2020 RAMP

In PG&E's 2017 RAMP, the three CCFs— Records and Information Management (RIM), Skilled and Qualified Workforce (SQWF), and Climate Resilience, (now Climate Change)—were aggregated across individual risk models. PG&E had developed a cross-cutting model that was dependent on the outputs from the other stand-alone risk models. The cross-cutting models were not specific risk events, but an aggregation of the associated stand-alone models. For example, for the RIM CCF, each of the stand-alone models estimated what portion of the risk could be attributed to a records issue. The portion attributed to records issues was an input into the RIM cross-cutting model.

In the 2020 RAMP, PG&E changed its approach to presenting and modeling CCFs, integrating each applicable CCF into the appropriate RAMP risk models as a driver, driver component, or consequence of that specific risk. The same approach is taken in the 2024 RAMP.

B. Mapping the CCFs to the 2024 RAMP Risks

Tables 3-1 and 3-2 below map the seven CCFs to the twelve RAMP risks. Table 3-1 shows how the CCFs impact the likelihood of a risk event while Table 3-2 shows how the CCFs impact the consequence of a risk event. PG&E also provides an individual table for each of the CCFs in each CCF section below that maps the CCF to the applicable RAMP risks.

The visibility of CCFs in the Bow Tie figures included in each RAMP chapter reflect the nature of the quantification of each CCF. Where the CCF can be included as a stand-alone driver or sub-driver with specific event frequency (e.g., Physical Attack) or as a stand-alone outcome (e.g., Seismic – Rupture), the CCF will be visible at this summary level. Certain CCFs that quantitatively impact the likelihood or consequences of the risk event will not appear on the Bow Tie, as the impact is embedded within the model underlying the frequency or consequence values (e.g., escalating Natural Hazard frequency over time due to Climate Change). For each of these four CCF examples, there would be a "Yes" relationship between CCF and Risk Event because there is some quantified connection between the CCF and the Risk Event. For others, where the connection is perhaps not sufficiently clear as to be quantified or difficult to distinguish within the available risk event data, CCFs have a "Yes*" mapping to indicate that there is a relationship between the CCF and Risk Event, but not one that is quantitatively modeled. For example, for the EP&R CCF, if a risk event occurs such as Loss of Containment on Gas Transmission Pipeline and PG&E implements EP&R activities (PG&E activates the Emergency Operations Center (EOC)), EOC activities (e.g., coordination with first responders), which are essential to manage/contain the consequence of the risk event, the degree to which this broad set of response activities reduces risk is not readily quantifiable.

TABLE 3-1
MAPPING THE CROSS-CUTTING FACTORS TO THE RAMP RISKS:
CROSS-CUTTING FACTORS IMPACT ON THE LIKELIHOOD OF THE RISK EVENT

Line No.	RAMP Risk	CCF						
		Climate Change	Cyber Attack	EP&R	IT Asset Failure	Physical Attack	RIM	Seismic
1	Contractor Safety Incident	Yes*	No	Yes*	No	Yes	No	No
2	Cybersecurity Risk Event	No	No	No	Yes*	Yes*	Yes*	No
3	Employee Safety Incident	Yes*	No	Yes*	No	Yes	No	No
4	Electric Transmission System-Wide Blackout	Yes	Yes	No	Yes*	Yes	Yes*	Yes
5	Failure of Electric Distribution Overhead Assets	Yes	Yes*	Yes*	Yes*	Yes	Yes	Yes
6	Failure of Electric Distribution Underground Assets	Yes	Yes*	Yes*	Yes*	Yes	Yes	Yes
7	Large Overpressure Event Downstream of Gas Measurement and Control Facility	Yes*	Yes*	No	No	Yes*	Yes	No
8	Large Uncontrolled Water Release (Dam Failure)	Yes*	Yes*	No	Yes	Yes	No	Yes
9	Loss of Containment on Gas Distribution Main or Service	Yes*	No	No	No	Yes	Yes	Yes
10	Loss of Containment on Gas Transmission Pipeline	Yes*	No	No	No	Yes	Yes	Yes
11	Public Contact with Intact Energized Electrical Equipment	No	No	No	No	Yes	Yes*	No
12	Wildfire	Yes*	Yes*	No	Yes*	Yes	Yes*	Yes

Yes — The cross-cutting factor has been quantified in the model.
Yes* — The cross-cutting factor does influence the baseline risk, but has not been quantified in the model, or the cross-cutting factor may influence the baseline risk but further study is needed.
No — The cross-cutting factor does not meaningfully influence the baseline risk.

TABLE 3-2
MAPPING THE CROSS-CUTTING FACTORS TO THE RAMP RISKS:
CROSS-CUTTING FACTOR IMPACT ON THE CONSEQUENCE OF THE RISK EVENT

Line No.	RAMP Risk	CCF						
		Climate Change	Cyber Attack	EP&R	IT Asset Failure	Physical Attack	RIM	Seismic
1	Contractor Safety Incident	No	No	No	No	No	Yes*	No
2	Cybersecurity Risk Event	No	No	Yes*	Yes*	Yes*	Yes	No
3	Employee Safety Incident	No	No	No	No	No	Yes	No
4	Electric Transmission System-Wide Blackout	Yes*	Yes	Yes*	Yes*	No	Yes	No
5	Failure of Electric Distribution Overhead Assets	No	Yes*	Yes*	Yes*	No	Yes	Yes
6	Failure of Electric Distribution Underground Assets	No	Yes*	Yes*	Yes*	No	Yes	Yes
7	Large Overpressure Event Downstream of Gas Measurement and Control Facility	No	Yes*	Yes*	Yes*	No	Yes	No
8	Large Uncontrolled Water Release (Dam Failure)	No	No	Yes	No	No	Yes	No
9	Loss of Containment on Gas Distribution Main or Service	No	No	Yes*	No	No	Yes	Yes
10	Loss of Containment on Gas Transmission Pipeline	No	No	Yes*	No	No	Yes	Yes
11	Public Contact with Intact Energized Electrical Equipment	No	No	No	No	No	No	No
12	Wildfire	Yes	Yes*	Yes*	Yes*	No	Yes	Yes*

Yes The cross-cutting factor has been quantified in the model.

Yes* The cross-cutting factor does influence the baseline risk, but has not been quantified in the model, or the cross-cutting factor may influence the baseline risk but further study is needed.

No The cross-cutting factor does not meaningfully influence the baseline risk.

C. Modeling the CCFs

1. Incorporating CCFs into the RAMP Risk Bow Ties

PG&E provides a detailed discussion of the Cost-Benefit Approach, Risk Value, and CBR methodology used to quantitatively assess risks and mitigations throughout this report in Exhibit (PG&E-2), Chapter 2. As described above, the seven CCFs are incorporated into the applicable RAMP risk models.

Since the CCFs impact the RAMP risks in different ways, PG&E used six different modeling methods to incorporate them into the RAMP risk models. These methods are described in the individual CCF sections below. The method(s) used to quantify a CCF in a risk event is noted in the Modeling Method column of each CCF's "Impacts to the 2024 RAMP Risks" section.

a. Driver

To determine the likelihood of an event, PG&E modeled the cross-cutting drivers using two methods.

Extracted from Existing: PG&E reviewed the historical causal data related to risk incidents and identified cross-cutting events that impacted the RAMP risk. The CCF events were extracted from the historical data and modeled or considered as a separate driver. The "Extracted from Existing" method generally represents the impact of CCFs considering the current application of controls. For example, when modeling the effect of the Physical Attack CCF on the Employee Safety Incident risk, PG&E relied on and applied historical data related to the different types of employee safety incidents assuming the data incorporates existing controls to reduce the likelihood of physical attack.

Added Frequency: PG&E added frequency based on separate quantification efforts outside of historical data. This method was generally used to represent low frequency events where additional quantification was added to the model to represent the potential impact of the CCF. For example, for the Failure of Electric Underground Distribution Assets risk, PG&E has very limited historical data on how major seismic events impact those assets, so to model the Seismic

CCF, PG&E used stand-alone seismic modeling, rather than historical observations, to characterize Seismic risk.

b. Consequence Multiplier

Reflects an adjustment to the Consequence of Risk Event due to the impact of the CCF. This method was generally used to represent the cumulative effect of the concurrent occurrence of the RAMP risk event and the CCF. For example, RIM issues can impact the financial consequence of a risk event in identifying and producing records after an event. This impact is expressed in the model by adding a multiplying factor to the financial consequences of an event. Note that penalties and fines are excluded from the financial consequences (including RIM multipliers) in the risk model.

c. Outcome

In certain instances, PG&E recognizes a unique Outcome for the CCF, where a risk event driven by or coincident with a CCF is has a different consequence profile than it would in the absence of that CCF. For example, for the Loss of Containment on Gas Transmission Pipeline risk, there may be simultaneous Rupture events due to a large-scale earthquake in the San Francisco Bay Area. The per-event consequences are expected to be higher in this scenario, so the model includes separate outcomes (e.g., Seismic – Rupture) for modeling consequences for the Seismic driver events.

d. Escalating Frequency

This is an adjustment to driver frequency. This method is generally used to represent a CCF that is expected to lead to an increase in the frequency of a risk event occurring, though it can represent a decrease. For example, for the Distribution Overhead Asset Failure risk, the model assumes that climate changes (CCF: Climate Change) will increase the frequency of events in the Natural Hazard sub-driver category (like heatwave occurrence, lightening, fire, and flooding) over time and, as such, an escalating frequency multiplier is applied to the risk driver.

e. Embedded

The impact of the CCF is already accounted for in the assessment of frequency and consequence of a risk event as a control. For example, the model assumes that the impacts of the EP&R CCF are already accounted for in the current Loss of Containment on Gas Transmission Pipeline risk and no additional EP&R data is added to the baseline risk assessments. PG&E is not able to cleanly distinguish the risk contribution from Embedded CCFs.

2. Calculating a CBR

PG&E describes below the basic process by which each CCF is represented in the risk model. The source documents used in each of the CCF models are included in supporting workpapers (WP). For CCF mitigation and control programs with a CBR calculated, CBR workpapers are also included.[2] Not all CCFs have programs with computed CBRs. While all CCFs mentioned in this report are essential to PG&E's safe and reliable provision of service, there are limitations to how the full benefit of CCF spend can be represented in the current risk framework. As noted in Section B, not all CCFs are quantitatively represented in Risk Event models, and not all types of quantification allow for a straightforward estimation of the necessary quantities to compute risk reduction (e.g., program exposure, mitigation effectiveness by driver and outcome). Even if PG&E were to present CBRs for CCF programs in this RAMP report, those CBRs do not capture the full risk reduction benefit for two reasons: 1) CCF programs impact additional risks on PG&E's CRR beyond the twelve RAMP risks on which the calculation would be focused and, 2) limitations in the current level of modeling maturity related to CCF impacts on risk.

Calculating the CBR incorporates cost estimates and the effectiveness of each mitigation. PG&E discusses CBRs in Exhibit (PG&E-2), Chapter 2. Risk reduction and CBRs for CCF programs are computed in the same way as for Risk Event programs, by specifying how effective a CCF program is in reducing driver frequency and attribute consequences, though CCFs have

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[2] Supporting workpapers include the CBR workpapers for each CCF whose mitigation or control programs have a CBR computed. See Exhibit (PG&E-2), WP RM-CCF organized by CCF.

an additional step of mapping CCF program to Risk Events and aggregating the LoRE and CoRE data across mapped risks.

In the individual CCF sections below PG&E provides an overview of the CCF and the 2024-2030 mitigation and control programs planned for each CCF.

D. Climate Change

1. Overview

Climate change presents ongoing and future risks to PG&E's assets, operations, employees, customers, and the communities in which it serves. Given the breadth and scale of these potential impacts, PG&E designated Climate Change as an enterprise risk in 2017. As the Company continued to evaluate the best approach to include climate change impacts in the Company's enterprise risk modeling, Climate Change was redefined as a CCF in the Company's 2020 RAMP report and PG&E continues to use this approach.

The California Public Utilities Commission (CPUC) has two open proceedings that consider with how utilities should incorporate climate change impacts in their risk assessment processes—Phase III of the Order Instituting Rulemaking (OIR) to Further Develop a Risk-Based Decision-Making Framework proceeding (Rulemaking (R.) 20-07-013) and Phase II of the Climate Adaptation OIR proceeding (R.18-04-019).

In line with the ongoing Climate Adaptation OIR, PG&E will be filing the Company's first Climate Adaptation Vulnerability Assessment (CAVA) concurrently with the 2024 RAMP report in May 2024. Findings from the CAVA have been used to assist in identifying the types of impacts that future climate hazards will have across PG&E's assets, operations, and services. This includes ongoing "foundational work" that seeks to improve PG&E's internal capabilities to understand, analyze, and use forward looking climate data in decision-making.

PG&E continues to work to further the use of climate change projection data in the Company's risk modeling as our understanding of the nature of climate change and the impact to our operations and assets grows. PG&E had previously identified six primary climate-driven contributors to risk:

increased severity and frequency of storm events; sea level rise; land subsidence; change in temperature extremes; changes in precipitation patterns and drought; and wildfire. These climate hazards were considered as part of the Company's 2024 CAVA. Key findings from this risk assessment indicate that the consequences of extreme weather events and changes to the weather conditions our assets face could result in severe customer impacts including service disruptions, property damage or other economic losses, and injuries or loss of life. In addition, PG&E could also sustain significant impact to its business.

2. Modeling

PG&E continues to work to further the use of climate change projection data in the Company's risk modeling as our understanding of the nature of climate change and the impact to our operations and assets grows. Due to the complexity of the overall RAMP risk quantification process and complexity of climate risk modeling, the Company believes the best approach is for the development of an iterative process that builds on previous analysis and insights.

Given the range of potential future conditions, and because historical data is often inadequate for understanding how future conditions may impact communities and infrastructure, it can sometimes be difficult to determine how climate change may impact the RAMP risks. Furthermore, Climate Change does not necessarily impact (or materially impact) each risk event. To integrate climate data into the risk model, each risk was considered individually, and available climate projections matched to appropriate drivers or consequences. For certain risks, a lack of data precluded integration of climate projections, even though PG&E expects these risks to be impacted by climate change.

Table 3-3 shows the status of climate data integration into the risk models.

TABLE 3-3
CCF SUMMARY: CLIMATE CHANGE

Line No.	Risk	Status of Climate Data Integration	Explanation of Climate Change Quantification Status
1	Loss of Containment on Gas Transmission Pipeline	Not currently integrated	CAVA findings indicate limited impact of Climate Change to gas transmission assets. Additional research is needed to determine the impact to a Loss of Containment event.
2	Loss of Containment on Gas Distribution Main or Service	Not currently integrated	CAVA findings indicate limited impact of Climate Change to gas distribution main or service assets. Additional research is needed to determine the impact to a Loss of Containment event.
3	Large Overpressure Event Downstream of Maintenance and Construction (M&C) Facility	Not currently integrated	CAVA findings indicate limited impact of Climate Change to gas M&C assets. Additional research is needed to determine the impact to a large overpressure event.
4	Wildfire	Integrated into Model	Includes modeling of Fire Weather Index. For further details, see Exhibit (PG&E-4), Chapter 1
5	Electric Transmission System-wide Blackout	Integrated into Model	Includes the impact of fire, heat waves, and storm changes. For further details, see Exhibit (PG&E-4), Chapter 2
6	Public Contact with Intact Energized Electric Equipment	Not applicable	Available data shows limited historical natural hazard impact
7	Failure of Electric Distribution Overhead Assets	Integrated into Model	Included the impact of heat waves, wildfire, flood, lightning, storm, and snow/ice. For further details, see Exhibit (PG&E-4), Chapter 4.

TABLE 3-3
CCF SUMMARY: CLIMATE CHANGE
(CONTINUED)

Line No.	Risk	Status of Climate Data Integration	Explanation of Climate Change Quantification Status
8	Failure of Electric Distribution Underground Assets	Integrated into Model	Included the impact of wildfire, flood, lightning, storm, and snow/ice. For further details, see Exhibit (PG&E-4), Chapter 5.
9	Large Uncontrolled Water Release (Dam Failure)	Not explicitly integrated; de facto integrated via existing FERC risk methodology	Required Federal Energy Regulatory Commission (FERC) dam risk assessment is conservative by design and incorporates consideration of past observed and likely future events when considering the magnitude of extreme floods. Additional analysis is needed to determine a relationship between climate hazards and increased debris flow and sedimentation.
10	Cybersecurity Risk Event	Not applicable	Available data shows limited historical natural hazard impact
11	Contractor Safety Incident	Not currently integrated	Additional research is needed to develop statistical relationship between future climate conditions that will result in contractor safety incidents.
12	Employee Safety Incident	Not currently integrated	Additional research is needed to develop statistical relationship between future climate conditions that will result in employee safety incidents.

Though Climate Change is a CCF, it does not necessarily impact (or materially impact) each risk event. PG&E's Enterprise & Operational Risk Management (EORM) team solicited feedback from each Functional Area (FA) risk owner on the impact of all CCFs to each risk event. Additionally, the Climate Resilience Team evaluated all RAMP risks in partnership with Risk Owners and asset family Subject Matter Experts (SME) to ensure that the Company's 2024 CAVA results were used to inform this evaluation and help to determine levels of exposure and sensitivity of natural hazards to each risk event. This involved consideration of each risk's sensitivity to climate-driven natural hazards, and determination of whether existing climate data could be integrated into risk Bow Ties in a statistically meaningful manner.

In some cases, the Climate Resilience Team and FA representatives agreed that climate-driven natural hazards would likely impact or continue to impact the risk in the future, but at this time the available data to quantify this relationship had yet to be developed. There remain challenges in fully integrating climate data into the enterprise risk models due to a number of factors. These include: (1) availability of historical data to determine a statistical relationship between climate hazards and failures, (2) difficulty in creating a relationship between individual climate change variables and risk events that can be caused by multiple weather variables acting in concert, (3) lack of available climate change data, and (4) limited availability of models connecting changing climate conditions to future weather conditions for all meteorological variables of interest.

PG&E intends to continue to advance the inclusion of forward-looking climate data into PG&E's RAMP risk models in future filings and to continue to leverage the findings from the Company's 2024 CAVA. These efforts will supplement the Company's understanding of how climate-driven natural hazards may impact PG&E in the future.

One way climate change can impact a risk is to increase the likelihood of a risk event and act as a frequency multiplier. The model considers how the climate variable will change (often, increase) over time and therefore impact PG&E's operations. For the Failure of Electric Distribution Overhead Assets risk, PG&E conducted analysis of prior asset failures during heat waves and conducted analysis of the likelihood of these conditions occurring again in the future. The results of this analysis are used to estimate how rising temperatures will impact PG&E's electric assets by comparing the rising temperature data to the electric assets failure rates based on the temperature threshold at which equipment is likely to fail. PG&E also considered other natural hazards for this risk, including major rain events, major snow/ice events, lightning, flooding due to extreme precipitation, and others. Failure of Electric Distribution Underground risk also included the estimated impact of projected change in wildfire, flooding, lightning, major rain events, and major snow/ice events in the likelihood of risk events for applicable sub-driver of natural hazard driver. In the Electric Transmission System-wide Blackout risk, PG&E considered the likelihood of various extreme weather events, which when combined with other issues could cause a risk event. To reflect the impact of these changing climate conditions on this risk, PG&E used climate projections to determine how the frequency of these natural hazard sub-drivers could change over time and impact the frequency of risk occurrence.

In contrast, climate change is accounted for in PG&E's Wildfire risk model on the consequence side of the model by correlating projected changes in the Fire Weather Index (FWI),[3] as a proxy for red flag warning conditions, or conditions with higher probability of wildfire ignition and spread. The FWI is used as measure of the likelihood of potential future weather conditions in a way that incorporates fuel aridity and fire weather, including daily-averaged temperature, relative humidity, wind speed, and precipitation, irrespective of fuel type and abundance. Both red flag warning conditions and high FWI values are associated with warmer temperatures, lower humidities, and stronger winds. This increases the proportion of ignitions originating from PG&E equipment that occur under high FWI conditions, which is correlated with higher consequence wildfires. This correlation is valid because projections of future area burned and high FWI

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3 Michael Goss, et al., Climate change is increasing the likelihood of extreme autumn wildfire conditions across California (2020), available at: <https://iopscience.iop.org/article/10.1088/1748-9326/ab83a7?ftag=MSF0951a18> (accessed May 3, 2024).

conditions are both driven by underlying factors, like higher temperatures and drier fuels, that are expected to result in more frequent and extreme fires due to climate change.

In addition to quantifiably impacting the Failure of Distribution Overhead Assets, Electric Transmission Systemwide Blackout, Failure of Distribution Underground, and Wildfire risks, PG&E considers climate change to be an applicable sub-driver to all other RAMP risks except Public Contact with Intact Energized Electrical Equipment and the Cybersecurity Risk Event.

PG&E was not able to quantify the impact of climate change on these risks at this time due to limited time and capabilities for internal research partnerships that are needed to create the quantifiable relationships of past failure events and climate hazard conditions, which allow for analysis of future climate conditions to determine how the rate of failure events may change in the future.

In many cases, the contribution of climate-impacted natural hazard sub-drivers to risk event frequency was negligibly low relative to other drivers based on historical data. Given that climate change is projected to increase the frequency and intensity of some natural hazard sub-drivers—thereby, making these sub-drivers greater potential contributors to risk in the future—PG&E plans to conduct further research to better quantify the impact of climate-driven hazards on these risks for the 2028 RAMP filing and as part of efforts to integrate climate data into appropriate operational risk models as well as conducting the Company's second CAVA.

3. Impacts to the 2024 RAMP Risks

Climate Change impacts 10 RAMP risks as shown in Table 3-4 below. PG&E is proposing alternative mitigations to address Climate Change for the following RAMP risks: (7) Large Uncontrolled Water Release (Dam Failure) and (9) Loss of Containment on Gas Transmission Pipeline.

TABLE 3-4
CCF SUMMARY: CLIMATE CHANGE

Line No.	RAMP Risk	Modeling Method[(a)]	Risk Frequency, Percentage (Events/Year)	Percent of Risk
1	Contractor Safety Incident		(b)	--
2	Employee Safety Incident		(b)	--
3	Electric Transmission Systemwide Blackout	Escalating Frequency	(c)	(c)
4	Failure of Electric Distribution Overhead Assets	Escalating Frequency	(c)	(c)
5	Failure of Electric Distribution Underground Assets	Escalating Frequency	(c)	(c)
6	Large Overpressure Event Downstream of Gas Measurement and Control Facility		(b)	--
7	Large Uncontrolled Water Release (Dam Failure)		(b)	--
8	Loss of Containment on Gas Distribution Main or Service			
9	Loss of Containment on Gas Transmission Pipeline			
10	Wildfire	Consequence Multiplier	(c)	(c)

(a) The modeling method(s) employed to quantify the CCF. Where the CCF is mapped to the risk event but the modeling method has not yet been established and/or implemented, the entry is blank. See Section C.1 for method explanations.

(b) The CCF influences the baseline risk, but risk from the CCF has not been explicitly quantified.

(c) Climate change has minimal impact on Frequency and Risk in the near term (i.e., during the GRC period). Climate Change modeling is further addressed in the Proposed Decision (PD) in Phase III of the Risk OIR, R.20-07-013, and PG&E will implement any requirements arising from the PD as required.

4. Change Since the 2020 RAMP

In the 2020 RAMP, PG&E considered Climate Change as a CCF to acknowledge that climate driven natural hazards are contributing to many RAMP risks, and this continues to be the case in PG&E's 2024 RAMP. Relative to the 2020 RAMP, PG&E has made improvements on three fronts: (1) recency of climate projection data used, (2) granularity at which climate data are incorporated into the modeling, and (3) integration of the relationship between climate change and a degradation in asset health. These improvements are as follows:

1. Where feasible, PG&E uses CMIP6[4] climate data to estimate how changing climate variables will affect the risk event. This updated data is used to estimate frequency escalation for temperature-related and wildfire natural hazard drivers.
2. PG&E uses granular climate variable data to compute tranche-level frequency escalation values for high temperatures and fire-related hazards. For example, in the Wildfire risk model, FWI data are computed by Circuit Segment (CS) or Transmission Route and then aggregated to compute tranche-level data. Similarly in the Failure of Electric Distribution Overhead Assets, fire and heat climate data are computed by CS and then aggregated to tranche-level frequency escalation factors.
3. In the Failure of Electric Distribution Overhead Assets model, PG&E includes climate modeling to escalate likelihood of heat-driven Equipment Failure due to heat stress (with escalation differentiated by tranche) relative to historical observations. This driver had not previously had any climate integration.

In addition, findings from the 2024 CAVA are being used throughout the Company's enterprise risk modeling efforts to further identify impacts of climate change to risk events and help in prioritizing the additional research needed to quantify these impacts.

In the 2020 RAMP, PG&E identified six mitigations that together comprised the foundational activities PG&E planned to undertake to better understand the risks posed to the Company by climate change and to increase the Company's climate resilience.

PG&E completed two of the mitigations proposed in the 2020 RAMP: (CLIMT-M5C – Develop and Report Climate Resilience Metrics; and CLIMT-M11 – Climate Vulnerability Assessment).

4 This set of data is aligned with the IPCC's sixth assessment report, and California's fifth climate assessment.

5. 2024-2030 Controls and Mitigations

a. Planned Work

PG&E is continuing to work on the other four foundational mitigations previously proposed and three new foundational mitigation programs. This ongoing and future work is detailed below:

- **CLIMT-M08 – Research Climate Science and Impacts**: PG&E is developing an internal climate change data storage project. The aim of this project is to support additional climate change data analysis, including the Climate Resilience Team's Internal Consulting (M13) and the next iteration of the Climate Adaptation Vulnerability Assessment (M14). To achieve this, PG&E is creating a repository of climate projection datasets to use within the Company's internal data infrastructure to allow for the pairing of asset data with these climate change projection datasets. The longer-term aim for this foundational effort will be to create: (1) data tools that other groups within PG&E can utilize to better plan for the impacts of climate data; and (2) methods to easily share climate data sets to different business units that have a need for climate data and to create a tool to visualize the impacts of different climate conditions to PG&E infrastructure and assets. To support this effort, an ongoing review of climate change science and available data will be required to ensure that the Company's risk mitigation efforts are reflective of these changes as new climate models are developed and additional research on climate risk is published. PG&E will also be conducting studies to better understand new climate data that is released as part of the Fifth California Climate Assessment.[5]
- **CLIMT-M10 – Governance, Integration, and Continuous Improvement**: This mitigation includes several efforts, including the development of a strategic plan that will help to govern the Company's efforts to build climate resilience and proactively plan for

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[5] Governor's Office of Planning and Research, Climate Assessment, Science, and Research, California's Fifth Climate Change Assessment, research priorities, and tools, available at: <https://opr.ca.gov/climate/icarp/climate-assessment/> (accessed May 3, 2024).

the expected impacts of climate change across the entire business. In 2022, PG&E joined Electric Power Research Institute's Climate Adaptation Resilience and Adaptation Initiative.[6] This effort is aimed at developing best practices for electric utilities to perform climate adaptation vulnerability assessments and integrate climate resilience into electric utility planning. This EPRI-led effort is expected to conclude in 2025. PG&E has made a commitment to become more climate resilient.

- **CLIMT-M12 – Climate Adaptation Plans**: With the completion of the Company's first CAVA, PG&E will begin developing Climate Adaptation Plans to support an integrated funding request as part of future general rate case requests. These adaptation plans will be developed by primary climate hazard and will include sea level rise, extreme heat, and extreme storms/inland flooding. PG&E intends these adaptation plans to be developed in partnership with the functional areas and where appropriate to partner with external stakeholders.
- **CLIMT-M13 – Internal Consulting**: The Climate Resilience team receives requests from the FAs to undertake ad hoc projects related to integrating forward looking climate data into project planning and asset replacement forecasts. This includes developing new statistical tools using climate projection data and the Company's asset data as well as developing detailed engineering focused studies to better understand how expected asset lifetimes will be impacted by various climate hazard conditions. PG&E is considering additional studies in partnership with other groups at the Company to better understand the impacts of climate change. These projects are expected to include an increased partnership with Emergency Planning & Response to better understand how extreme weather will impact the Company's emergency management activities.

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6 EPRI, Climate READi: Power Resilience and Adaptation Initiative, available at: <https://www.epri.com/research/sectors/readi> (accessed May 3, 2024).

PG&E will have three new foundational mitigations:

- **CLIMT-M14 – Climate Adaptation Vulnerability Assessment 2.0**: Consistent with R.18-04-019, PG&E will begin its second Climate Adaptation Vulnerability Assessment. The Company's first assessment was completed in phases and took several years to complete, and PG&E expects the Company's second assessment to take two years to complete. The scope of this assessment will be similar to the previous assessment and will include more detailed analysis of moderate and high climate risk assets. To support this effort, PG&E is expanding its internal capabilities to store and analyze climate change projection datasets with the aim to integrate these efforts with PG&E's asset exposure data, which is included as part of the Research Climate Science and Impacts mitigation (M8). In addition, PG&E will work with various stakeholders throughout the CAVA 2.0 process consistent with the CPUC's future requirements for Community Engagement and outreach to disadvantaged and vulnerable communities.
- **CLIMT-M15 – Climate Informed Risk Assessment**: PG&E has found that integrating climate data into enterprise and operational risk models is a time and resource intensive effort. Consistent with Phase III of the OIR to Further Develop a Risk-Based Decision-Making Framework proceeding (R.20-07-013), PG&E will continue to develop more quantitatively informed enterprise risk models in the Company's next RAMP filing. This effort will expand on the existing climate-informed risk modeling efforts to include scenario analysis and an expansion of risk models that have difficult to quantify relationships between climate hazard conditions and risk events.
- **CLIMT-M16– Climate Informed Design Guidance**: A key finding from the Company's first CAVA was that updating design standards for assets was a key first step to building climate resilience. PG&E has updated one electric design standard. The process to update these standards requires extensive partnership across the Engineering Planning & Strategy teams and analysis of future

climate data. PG&E intends to expand its initial efforts and conduct a broader review of key design standards that currently use or rely on historical weather data, with the intent to update relevant standards for new equipment to ensure that they are designed for the potential future conditions due to climate change.

Cost estimates for the planned mitigations are shown in Table 3-5 below.

TABLE 3-5
MITIGATION COST ESTIMATES
2024-2030 EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Mitigation ID	Mitigation Name	Major Work Category (MWC)	2024	2025	2026	2027	2028	2029	2030	Total
1	CLIMT-M08	Research Climate Science and Impacts	LJA	$506	$513	$420	$352	$359	$466	$473	$3,089
2	CLIMT-M10	Governance, Integration, and Continuous Improvement	LJA	676	719	275	282	288	294	301	2,835
3	CLIMT-M12	Climate Adaptation Plans	LJA	56	533	652	407	607	617	170	3,042
4	CLIMT-M13	Internal consulting projects	LJA	475	351	233	236	389	394	248	2,326
5	CLIMT-M14	Climate Adaptation Vulnerability Assessment 2.0	LJA	319	0	904	1,118	50	0	861	3,251
6	CLIMT-M15	Climate Informed Risk Assessments	LJA	295	354	532	620	633	496	509	3,439
7	CLIMT-M16	Climate-Informed Design Guidance	LJA	350	886	1,239	1,243	1,534	1,546	755	7,553
8		Total		$2,677	$3,357	$4,255	$4,258	$3,860	$3,813	$3,315	$25,534

Note: The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

b. Mitigations With CBRs

PG&E did not calculate CBRs for Climate Change because the Climate Change mitigations are foundational activities not as of yet directly enabling any risk reducing programs. As discussed in Exhibit (PG&E 2), Chapter 2, foundational activities are programs that enable two or more control or mitigation programs but do not directly reduce the consequences or the likelihood of risk events.

E. Cyber Attack

1. Overview

The Cyber Attack cross-cutting factor is defined as a coordinated malicious attack purposefully targeting PG&E's core business functions, increasing the likelihoods and/or consequences of risk events in the CRR.

The different ways through which the Cyber Attack cross-cutting factor can affect different RAMP risks are described below in section E.3, "Impacts to the 2024 RAMP Risks".

The threat landscape and PG&E's controls and mitigations to address the Cyber Attack cross-cutting factor and the Cybersecurity Risk Event are described in detail in Exhibit (PG&E-7), Chapter 2.

2. Modeling

Cyber vulnerabilities and ever-evolving threats can impact both the likelihood and consequence of a risk event. While mapped to multiple risk events, this CCF is explicitly modeled in one RAMP risk, Electric Transmission Systemwide Blackout, as a driver/outcome combination. This modeling represents the potential for a cyber-attack to cause grid emergency conditions and reflects the longer recovery time of such an emergency. The likelihood estimate is based on a review of a dataset of historical grid emergencies and US widespread blackouts that included cyber-attack information (see Exhibit (PG&E-4), Chapter 2 for more information), and the degree to which such an event is prolonged is informed by SME judgment.

The use of industry and SME information is consistent with the modeling approach in the Cybersecurity Risk Event model. PG&E does not have internal data wherein a cyber-attack resulted in a catastrophic risk event, and the availability of directly relevant data is challenging and details are often held back from what is shared publicly. PG&E Cyber SMEs depend on data collected from government partners, claims data for North American Utility and Power Generation sectors, paid and public third-party reports and surveys, and has built a cyber-attack event dataset to support Cybersecurity Risk Event modeling which also informs SME discussions around Cyber Attack CCF risk.

PG&E's emphasis for modeling cyber risk has been the design and improvement of the Cybersecurity Risk Event Bow Tie rather than iterating over Cyber Attack CCF modeling. Solely representing Cyber Attack as a CCF underestimates cyber risk, but cyber risk has a cross-cutting influence often exacerbating the consequences of an asset-based or operational risk event driven by other factors. Therefore, PG&E represents it using both modeling approaches.

3. Impacts to the 2024 RAMP Risks

Table 3-6 below, maps the Cyber Attack cross-cutting factor to the applicable RAMP risks.

TABLE 3-6
CROSS CUTTING FACTOR SUMMARY: CYBER ATTACK

Line No.	RAMP Risk	Modeling Method[(a)]	Risk Frequency, Percentage (Events/Year)	Percent of Risk
1	Electric Transmission Systemwide Blackout	Driver (Extracted from Existing)/ Outcome	0.8 percent (0.0001)	1 percent
2	Failure of Electric Distribution Overhead Assets		[(b)]	–
3	Failure of Electric Distribution Underground Assets		[(b)]	–
4	Large Overpressure Event Downstream of Gas Measurement and Control Facility		[(b)]	–
5	Large Uncontrolled Water Release (Dam Failure)		[(b)]	–
6	Wildfire		[(b)]	–

(a) The modeling method(s) employed to quantify the CCF. Where the CCF is mapped to the risk event but the modeling method has not yet been established and/or implemented, the entry is blank. See Section C.1 for method explanations.

(b) The CCF influences the baseline risk, but risk from the CCF has not been explicitly quantified.

Electric Transmission Systemwide Blackout

A Cyber Attack can cause a grid emergency and can extend the expected restoration time relative to a non-cyber grid emergency. This is modeled as a Driver frequency Extracted from Existing mapped to unique Outcome.

Failure of Electric Distribution Overhead Assets

A Cyber Attack on SCADA devices can lead to an unplanned outage by sending inaccurate data on the status of the device and disrupting the remote capability of SCADA devices.

Failure of Electric Distribution Underground and Network Assets

Like a Cyber Attack impact on Electric Distribution Overhead assets, a Cyber Attack can impact SCADA devices and lead to an unplanned outage.

Large Overpressure Event Downstream of Gas Measurement and Control Facility

A Cyber Attack can impact the consequences of a Large Overpressure Event Downstream of Gas M&C Facility or a Loss of Containment on Gas Transmission Pipeline. If a Cyber Attack that impacts gas Supervisory Control and Data Acquisition (SCADA) occurred during a risk event, it could amplify that event by reducing PG&E's visibility into the system, decreasing PG&E's ability to respond to the risk event.

Large Uncontrolled Water Release (Dam Failure)

A Cyber Attack can impact the likelihood of a Large Uncontrolled Water Release (Dam Failure) risk event. A Cyber Attack coincident with conditions that cause a dam failure (flood, seismic, internal erosion, or physical attack) will increase the likelihood that a catastrophic outcome will occur.

Wildfire

A Cyber Attack can lead to asset failures that can lead to an outage or ignition. Further, a loss of situation awareness could hamper PG&E's ability to respond to Wildfire risk events.

4. Changes Since the 2020 RAMP

In addition to being a CCF, Cybersecurity is also modeled as stand-alone risk event in RAMP. When modeled solely as a CCF, most often as a consequence multiplier, risk from cyber threat is underestimated as it is contingent upon asset failure or operational risk event happening due to other drivers. In modeling Cybersecurity as both a CCF and Risk, PG&E has sought to ensure that the impacts from each approach are mutually exclusive so that the overall Cybersecurity threat can be assessed using both approaches. Part of this strategy is to model Cyber Attack as CCF when directly relevant data are available to help characterize how a particular risk event is affected by cyber-attack, as is the case with Transmission System-wide blackout. As a result of driving mutual exclusivity, Cyber Attack is explicitly modeled in fewer risk events in PG&E's 2024 RAMP than their 2020 RAMP.

5. 2024-2030 Controls and Mitigations

A detailed description of PG&E's controls and mitigations for the Cyber Attack cross-cutting factor and the Cybersecurity Risk Event is presented in Section C of Exhibit (PG&E-7), Chapter 2. PG&E controls and mitigations are categorized and linked to PG&E Cybersecurity programs focused on Cybersecurity risk identification and management.

These controls and mitigations are focused on identification, assessment, and development of mitigation strategies to address the fluid nature of cybersecurity threats and threat actors and their possible impacts to PG&E. Individual controls and mitigations are mapped to the Identify, Detect and Protect control programs and address the threats identified in the cybersecurity bow tie (drivers).

F. Emergency Preparedness and Response

1. Overview

The EP&R CCF examines the drivers and consequences of inadequate planning or response to emergencies. Inadequate emergency planning or response and situational awareness could have significant safety, reliability, and regulatory impacts. Effective preparedness requires thorough planning, situational awareness, ample resources, community engagement and an active involvement from internal and external stakeholders to address potential risks effectively.

According to the Federal Emergency Management Agency (FEMA) 2023 National Preparedness Report,[7] climate-related disasters have been occurring with increasing frequency, severity, and cost of disasters. Among FEMA's recommendations, is to "Target Investments towards Particular Core Capabilities and Mission Areas." EP&R advances PG&E's response to emergencies by improving governance, strengthening coordination among the FAs and improving collaboration with external partners such as the FEMA and California Governor's Office of Emergency Services (Cal OES). EP&R requires integrated plans and the appropriate facilities, logistics, technology, and processes to respond to a catastrophic incident. Impacts of climate change is a driver of improvement efforts for EP&R.

Since the 2020 RAMP and 2023 GRC filings, PG&E has made some organizational changes to help focus EP&R resources on developing and executing EP&R strategy and integrating the Hazard Awareness and Warning Center (HAWC) and Geosciences resources into the overall approach for planning and responding to emergencies. The HAWC

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7 National Preparedness Report (fema.gov), https://www.fema.gov/sites/default/files/documents/fema_2023-npr.pdf.

operates as a centralized resource for real time situational awareness and intelligence as the center remains staffed 24/7. Examples of situations monitored by the HAWC include wildfire, debris flow, landslides, floods, and other extreme weather events. Geosciences provides risk-based seismic engineering, geologic, geophysical, and geotechnical services that support the safe and reliable operation of PG&E assets across the enterprise as well as various hazard situational awareness and initial emergency response/inspection tools before and after an earthquake. More information about Seismic risk can be found in Section J of this chapter.

2. Modeling

The EP&R CCF can impact the driver side of a risk event or consequence side of the risk event. Increased demands on response and restoration utility workers can increase the likelihood of Employee and Contractor Safety Incident risk events if the work-related fatigue and exposures to workplace hazards are not effectively managed during the emergency response. For other risks, EP&R is relevant after a risk event occurs by defining how PG&E responds to a risk event and reduces potential impacts and restoration timeframes. Since EP&R is an integral part of PG&E's operations, it is difficult to model the consequences of a risk event without EP&R controls or estimate the impact of mitigations in reducing consequences of a risk event. PG&E identified which RAMP risks that EP&R impacts but did not specifically quantify the impact of EP&R mitigations or controls in reducing the RAMP risks.

3. Impacts to the 2024 RAMP Risks

Table 3-7 below maps the EP&R CCF to the applicable RAMP risks.

TABLE 3-7
CCF SUMMARY: EP&R

Line No.	RAMP Risk	Modeling Method[a]	Risk Frequency, Percentage (Events/Year)	Percent of Risk
1	Contractor Safety Incident	Embedded	(b)	--
2	Cybersecurity Risk Event	Embedded	(b)	--
3	Employee Safety Incident	Embedded	(b)	--
4	Electric Transmission Systemwide Blackout	Embedded	(b)	--
5	Failure of Electric Distribution Overhead Assets	Embedded	(b)	--
6	Failure of Electric Distribution Underground Assets	Embedded	(b)	–
7	Large Overpressure Event Downstream of Gas Measurement and Control Facility	Embedded	(b)	–
8	Large Uncontrolled Water Release (Dam Failure)	Embedded	(b)	–
9	Loss of Containment on Gas Distribution Main or Service	Embedded	(b)	–
10	Loss of Containment on Gas Transmission Pipeline	Embedded	(b)	–
11	Wildfire	Embedded	(b)	–

(a) The modeling method(s) employed to quantify the CCF. Where the CCF is mapped to the risk event, but the modeling method has not yet been established and/or implemented, the entry is blank. See Section C.1 for method explanations.

(b) While this CCF impacts the RAMP risk, it was not extracted from the data and considered or modeled separately.

EP&R controls and mitigations help to reduce the impact of a catastrophic or severe risk event. If a catastrophic or severe risk event occurs, PG&E activates its EOC and/or alternate emergency centers. PG&E would then initiate the EP&R controls to help mitigate the impact of these events such as: coordinated responses between the Functional Areas to re-energize electric lines and re-pressurize gas pipelines; deploying and staffing base camps to enhance restorations efforts for customers; coordinated customer outreach activities; and communications with third-party responder agencies.

4. Changes Since the 2020 RAMP

In the 2023 GRC, EP&R modified its portfolio of mitigations and controls from those presented in the 2020 RAMP Report by consolidating eight mitigations representing various aspects of EP&R strategy, execution and geosciences programs into a single mitigation that consists of many of the 2020 RAMP Report mitigations. EP&R also consolidated twelve controls into two controls that include both 2020 RAMP Report controls and new controls. The new scope added to each control is:

<u>EPNDR-C000 – EP&R Controls</u>

- Earthquake Early Warning – expanded beyond pilot phase
- Debris Flow Modeling – wildfire, storm, and flood
- Enterprise-Wide GIS – standardizing GIS tools across the enterprise
- DASH – various technology enhancements

<u>EPNDR-C002 – HAWC Situational Awareness</u>

- HAWC Enterprise Advanced Radio System (EARS) – Installation of receivers around the service territory
- HAWC EARS Rapid Deployment – Rapidly deployable trailers to support emergency sites

In addition, the following controls have been removed from the EP&R control scope since the 2020 RAMP:

- C9 – Gas Systems Operations Temperature Forecasting.
- C10 – Power Generation Hydro Management Forecasting
- C11 – Short Term Electric Supply Forecasting, and
- C12 – Diablo Canyon Power Plant (DCPP) Emergency Response Organization Support

The majority of EP&R's programs are primarily labor-based and to track the program costs described in the planned work plan below, EP&R has determined that 45 percent of the organization program is allocated to mitigations and 55 percent is allocated to controls.

5. 2024-2030 Controls and Mitigations

EP&R is proposing two controls (EPNDR-C000 and EPNDR-C002) and one single mitigation (EPNDR-M000) with the details broken out below.

a. Planned Work

EPNDR-C000 – EP&R control: one EP&R control that consists of seven different activities: (1) Emergency Planning and Process Improvement, (2) Training, 3) Exercise, (4) Prevention, (5) Response, (6) Recovery, (7) Geosciences.

- Emergency Planning and Process Improvement includes publishing the annual Company Emergency Response Plan (CERP) that provides guidance on managing emergencies and establishing processes that are scalable to any hazard, developing hazard specific annexes,[8] and continuously improving emergency response functions.
- Training includes developing the Company Training Program for emergency preparedness and continuous process-improvement for all aspects of the EOC.[9] The training activities also includes developing roles and responsibilities for the EOC, training curriculum for EOC processes and positions, and supporting curriculum development for functional area emergency management teams. Training plays a crucial role by providing PG&E with a means of attaining, practicing, validating, and improving emergency preparedness capabilities.
- Exercise includes planning, coordinating, and executing emergency preparedness exercises[10] that develop PG&E's emergency response and recovery capabilities through a progressive building-block approach. Using the Homeland Security Exercise and Evaluation Program (HSEEP), the team develops exercises designed to test the effectiveness of current enterprise emergency response plans and procedures and to test PG&E's ability to respond to various emergencies, improve communications among partners, identify lessons learned, and engage senior leadership.
- Prevention includes researching and conducting the Threat Hazard Identification Risk Assessment (THIRA) to identify enterprise risks, conducting 3-year Business Impact Analysis (BIA), developing Business Continuity Planning based on the results of the BIA and

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[8] New annexes will be developed based on the Threat Hazard Identification Risk Assessment (THIRA) results.

[9] The training program is developed to align with State of California Standardized Emergency Management System and National Incident Management System principles for EOC operations.

[10] Exercises include internal and external emergency preparedness events, annual company-wide exercises and functional/hazard-specific exercises.

keeping the plans accessible.[11] This program develops the role and responsibility guidelines for the Company's Corporate Incident Management Council (CIMC), Business Continuity Executive Steering Committee, Business Continuity Directors, and Coordinators.

- Response ranges from maintaining the EOC to managing and coordinating the technology platforms used for key initiatives such as EOC, Emergency Communications, Mass Emergency Notification Systems, and Weekly Situational Awareness Calls (WSAC).
- Recovery manages the After-Action Reports (AAR) and process improvements to support the development and creation of AARs for All Hazards EOC Incidents. Initiatives include the development of Strategy & Execution's Key Performance Indicators (KPIs), as well as track KPIs for projects tied to safety, compliance, and risk.
- Geosciences:
  a. Earthquake Early Warning (EEW) – PG&E has been actively supporting and implementing U.S. Geological Survey and State EEW programs and technology. Examples include installing the MyShake app on company cellphones and engagement with EEW developers to pilot new technologies and providing end user feedback. Messaging and training employees to appropriately respond to earthquake warnings is a current priority. Beyond implementing EEW on company cellphones, PG&E is evaluating methods to connect EEW messaging via computer monitors, building public announcement systems, and field crew radios to increase the audience reached by EEW. Linking EEW to control systems has been piloted by connecting elevators in the former 77 Beale Street headquarters office with controls to stop the elevator at the next floor and open the doors to prevent trapping occupants. Based on the success of that program plans have been developed, and permitting is in

11 These efforts utilize the Fusion software and services.

progress, to install similar EEW elevator controls in the new Oakland General Office. Other potential EEW linkage to control systems are being evaluated for electric and gas system safety shutoffs; these applications have significant issues or constraints that need to be addressed before implementation.

b. Debris Flow Modeling: A significant number of facilities, access roads, and electric and gas assets located in terrain subject to debris flows triggered during high intensity precipitation events. Wildfire burn areas have a higher likelihood of debris flows until vegetation is reestablished. Increased fire risk and potential increases in high intensity storm events exacerbated by climate change appear to be increasing the threat and impact of debris flows. PG&E has implemented debris flow models and rain gauge installations to evaluate and monitor debris flow potential. The model results are used to issue hazard alerts for field crews and operations personnel. Plans and training have been developed for responding to debris flow alerts and hazard conditions, and the modeling also helps evaluate possible preparatory or mitigation actions for areas of highest hazard. The debris flow model undergoes a continuous improvement program that includes funding research and model development by the U.S. Geological Survey and academic and consulting groups. This includes integration of remote sensing capabilities, better understanding of geologic and climate conditions that trigger debris flows, and the latest processing techniques including advanced geospatial modeling and artificial intelligence. In addition to debris flows, other types of slope failure such as deep-seated landslides and rockfall are potential threats in steep terrain. A program is being developed to integrate all these slope failure types into a holistic model that will provide the same kind of monitoring and alert capabilities of the debris flow model. These efforts and models provide benefit beyond PG&E's use cases and are significantly contributing to the science and engineering community. Research and technology development funded and directed by PG&E is performed in a science community collaborative manner such that developments and knowledge gained are externally available and published in peer reviewed papers.

c. Dynamic Automated Seismic Hazard (DASH): The DASH application provides an assessment of impacts to PG&E facilities within minutes of a significant earthquake and informs emergency response and prioritization of initial damage evaluations (IDEs) in the critical hours following an event.

d. Enterprise-Wide GIS: GIS tools increase PG&E's situational awareness during emergencies. We currently use independent GIS tools such as the Transmission Integrity Management Program (TIMP) Geohazards program and Tactical Analysis Mapping Integration (TAMI) which support our responses to landslide, erosion, and ArcGIS Online.

The vision with Enterprise GIS is standardized data that has been spatially correlated to enable analysis of our assets. Analysis can be performed to look at trends (what is happening where and when) and can be used to assist in project planning (mitigations and construction) and hazard modeling. GIS can bring Geoscience based work/data to the forefront and implemented for multiple use cases.

EPNDR-C002 – HAWC Situational Awareness: Situational awareness is critical for hazard identification, effective decision making, and accident prevention. The HAWC Program serves as a control with the following:

(1) 24/7 staffed centralized hub for coordination, facilitation, and communications of all hazards for real time situational awareness and intelligence.

(2) HAWC Enterprise Advanced Radio System (EARS): Installation of receivers around the service territory to ensure first responder radio transmissions are available to be monitored by our team as well as other first responders and the public through the Broadcastify network. The EARS project team works with the PSS team to

identify underserved areas or gaps in coverage around the service territory to ensure radio feeds are available.

(3) HAWC EARS Rapid Deployment: Deployment of trailers that have wildfire cameras, mobile scanners and receivers that perform the same function as the general EARS and camera programs in a targeted manner. These trailers are rapidly deployable to emergency sites and situations to ensure radio feed and camera coverage for PG&E, first responders and other stakeholders.

EPNDR-M000 – EP&R Mitigation: The mitigation activities within EPNDR-M000 are primarily enhancements or new projects that align and improve efficiency in the controls described in EPNDR-C000 and EPNDR-C002. Examples of those enhancements include:

Emergency Planning and Process Improvement: Develop new incident specific annexes (plans) to provide guidance to the FA's to plan and document their responses to specific disruptions.

Training: Expanding EOC ICS training to REC, OEC, and GEC levels and developing technologies and process to track training certification that is integrated with FEMA and CSTI. In addition, evaluating strategic incident management training for rapidly expanding incidents that support collaboration with public partners during complex incidents.

Exercise: Technology Enhancements to support exercise design including, inject mapping, automated inject tracking and delivery, scenario building, and tablet-based Exercise Evaluation Guides, and AAR technology development to track corrective actions across different incidents and emergency centers to evaluate trends in gaps to strengthen execution of plans, processes, and core capabilities.

Response: EOC Facility Improvements, EOC Technology Improvements, enabling leaders to make informed decisions and coordinate their actions effectively and serve as a resource for external agencies.

Geosciences: DASH enhancements including mobile application development, SmartMeter integration, platform updates, and Restoration Work plan integration.

<u>HAWC Situational Awarenes</u>s: Expanding and exploring the Interra Application integration into the Hazard Awareness Tool (HAT) for first responder locations and updates; Pinpoint hazards (i.e., Fire, Flood, Avalanche, Tsunami, etc.) identification for locations, Public Safety and utility two-way real-time communication for data and information sharing; expansion of PG&E Aircraft Utilization for Hazard Mapping and Awareness

b. Mitigations With CBRs

PG&E determined a CBR for EP&R spend at this time to be ineffective on the risk reduction scores and were removed from the calculation. EP&R impact on risk is qualitative instead of quantitative.

G. IT Asset Failure

1. Overview

IT Asset Failure (ITAFL) risk is defined as the failure of IT hardware/infrastructure and/or software assets resulting in IT service interruption, system outage, degraded service or loss of redundancy. In the 2020 RAMP filing ITAFL was first presented as a CCF. As the data was further refined and analyzed in the 2023 GRC filing, ITAFL was then presented as a stand-alone risk with a Bow Tie, while maintaining its CCF status. The stand-alone ITAFL Bow Tie does not have modeled safety consequences, so it is not in scope for PG&E's 2024 RAMP filling. However, ITAFL as a CCF is in scope for this report as it is mapped to RAMP risks and will be discussed exclusively as a CCF in this report.[12]

IT services, hardware and software assets are vital to PG&E operations. Across all FAs, PG&E uses these assets to improve safety and reliability, meet compliance obligations, and engage with customers. They enable and support virtually all of PG&E's day to day activities, including work execution, grid control, customer support, emergency response, and asset management.

IT is pursuing ISO 55001 asset management certification which will help strengthen the foundation for organizing information for continuous

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12 PG&E expects that ITAFL will be presented in its hybrid form, as a stand-alone risk event with a quantified Bow Tie and as a CCF, in its TY2027 General Rate Case.

improvement in asset management and managing the risks associated with the assets. As IT Asset Failure risk analysis matures, PG&E will move towards a more granular analysis of interdependencies between the IT asset failure risk and other risks that considers the alignment between bow ties and the underlying tranches and drivers.

2. Modeling

PG&E's assessment of IT Asset Failure has identified potential CCF impacts to both likelihood and consequence of multiple risk events. This analysis was done by the FA risk teams and involved an assessment of how IT asset failure would materially impact their risk event. For most of the risk events, PG&E's assessment of the relationship between IT Asset Failure and the risk event was qualitative. The IT risk team then met with the FA RAMP risk teams to assess the most significant ways in which IT asset failure would impact the RAMP risk, focusing on the higher consequence outcome scenarios as determined by the SMEs. To assess how an IT asset failure would impact another risk event, the IT risk team assumed that the probability of an IT Asset Failure itself causing a risk event to occur was minimal. Further, the approach was to consider that if a risk event and an IT Asset Failure occur at the same time, it is possible that the likelihood of the risk event occurring could increase or the consequence of the risk event could be more significant due to the failure of the IT asset. The following approaches were discussed:

- <u>Increase in Likelihood</u>: Failure of an IT asset/system could cause failure of an asset used directly to prevent an event, or could, combined with other drivers, increase the likelihood of a risk event.
- <u>Increase in Consequenc</u>e: Failure of an IT asset could act like a Consequence Multiplier, for example, it could increase the impact of the risk event by creating delays in the detection, loss of visibility and delayed response to an event.

In this report, PG&E has presented IT Asset Failure as an added frequency for one risk—the Large Uncontrolled Water Release (Dam Failure) risk, as explained more in Section 3.

As described above, evaluating the risk of IT Asset Failure across the RAMP risks involved an assessment of IT asset failure scenarios that could impact the RAMP risks in different ways. Due to the complexities of the IT systems, the number of individual assets, and the complex and foundational relationships between the IT assets and the RAMP risks, it was challenging for the RAMP risk owners and IT risk team to use the existing data to quantitatively model how the failure of IT assets would directly impact a risk event. In addition to the individual IT assets, PG&E also struggled with how to quantitatively account for the "foundational" IT assets (e.g., networks, communication systems, etc.) in frequency/impact quantification and mitigation effectiveness calculations.

3. Impacts to the 2024 RAMP Risks

Table 3-8 summarizes of the quantification of IT Asset Failure as a CCF to the RAMP risk of Large Uncontrolled Water Release (Dam Failure). IT Asset Failure is an added frequency for this RAMP risk.

TABLE 3-8
CCF DRIVER SUMMARY: IT ASSET FAILURE

Line No.	RAMP Risk	Modeling Method[(a)]	Risk Frequency, Percentage (Events/Year)	Percent of Risk
1	Cybersecurity Risk Event		[(b)]	--
2	Electric Transmission Systemwide Blackout		[(b)]	--
3	Failure of Electric Distribution Overhead Assets		[(b)]	--
4	Failure of Electric Distribution Underground Assets		[(b)]	--
5	Large Overpressure Event Downstream of Gas Measurement and Control Facility		[(b)]	--
6	Large Uncontrolled Water Release (Dam Failure)	Sub-Driver (Added Frequency)	3 percent (0.001)	7 percent
7	Wildfire	Embedded	[(b)]	--

(a) The modeling method(s) employed to quantify the CCF. Where the CCF is mapped to the risk event but the modeling method has not yet been established and/or implemented, the entry is blank. See Section C.1 for method explanations.

(b) The CCF influences the baseline risk, but risk from the CCF has not been explicitly quantified.

Large Uncontrolled Water Release (Dam Failure)

An IT asset failure can impact the likelihood of a Large Uncontrolled Water Release (Dam Failure) risk event. An IT asset failure coincident with conditions that cause a dam failure (flood, seismic, internal erosion, or physical attack) will increase the likelihood that a catastrophic outcome will occur. The IT systems considered when analyzing IT Asset Failure risk were critical network components and mission critical communications systems supporting hydroelectric plants. Exhibit (PG&E-2), WP RM-CCF, IT-ITAFL-1 has more details about the calculations of the increase in likelihood of the dam failure event due to a coincident IT asset failure.

PG&E is continuing to evaluate the impact that IT Asset Failure has on other RAMP risks and expects to share new findings in a future report or proceeding.

4. Changes Since the 2020 RAMP

In PG&E's 2020 RAMP Report, IT Asset Failure was presented as a cross-cutting risk factor only, and not as a standalone risk event. Since then, PG&E has transitioned IT Asset Failure from a CCF to a standalone risk event and presented the first generation of the risk bow tie in the 2023 GRC, while also maintaining its status as a cross-cutting risk factor. Since the 2023 GRC, PG&E further refined the standalone risk bow tie model, which will be discussed in the 2027 GRC.

5. 2024-2030 Controls and Mitigations

a. Planned Work

PG&E has identified six IT Asset Failure risk mitigation programs that impact RAMP risks to some degree. Due to the interdependent nature of IT systems, these programs mitigate IT Asset Failure risk as a whole, and scope specific to mitigating RAMP risks is not distinguished within the overall program scope. The mitigations presented in the 2024 RAMP are an evolution of prior programs presented in 2020 RAMP and 2023 GRC, with more granular scope and tranches.

- **ITAFL-M007 – Lifecycle Existing Assets - Network Technologies**: This program focuses on replacement of IT Network Technology assets that have reached or exceeded their useful service life, are in poor health due to a variety of factors or are otherwise at elevated risk of failure. This helps to retain ongoing vendor support for parts, technical issues, and maintenance, which reduces the risk of extended outages resulting from IT asset failures. Replacement assets are selected to meet expected capacity needs for the life of the asset.

- **ITAFL-M008 – Add Resiliency/Redundancy – Network Technologies**: This program focuses on diversifying network connectivity at PG&E facilities, and implementing other technical and operational fail safes in the Network domain to maintain IT service continuity in the event of an IT asset failure. This helps to minimize the impact a single component failure might have on a complex, integrated system.
- **ITAFL-M009 – Upgrade IT Common Facilities Infrastructure**: This program focuses on replacement of IT Common Facilities assets that have reached or exceeded their useful service life, are in poor health due to a variety of factors or are otherwise at elevated risk of failure. This program also upgrades physical structures and adds resiliency/redundancy and capacity to power systems where needed to address changing business and technology requirements at a given location.
- **ITAFL-M010 – Network 20/20**: This targeted program focuses on: (a) upgrading/rearchitecting obsolete transport network assets (fiber and microwave systems and supporting infrastructure) that rely on decades old technology architecture, (b) upgrading operational support systems to manage/operate/monitor the new technology, and (c) remediating single points of failure in the transport network by establishing diverse network connections to critical facilities and adding resiliency/capacity to power systems where needed.
- **ITAFL-M011 – Integrated Grid Platform Communication Infrastructure Upgrades**: This program focuses on deploying a scalable, private wireless network to field locations and modernizing/rearchitecting network infrastructure supporting electric SCADA to support increasing demand for network capacity and

reliability at field locations (e.g., due to increased grid automation and SCADA network growth).

- **ITAFL-M13 – Lifecycle Existing Assets – Applications/Application Components**: This program focuses on replacement of Application/Software assets (including supporting hardware/software components where applicable) that have reached or exceeded their useful service life, are in poor health due to a variety of factors or are otherwise at elevated risk of failure. This helps to retain ongoing vendor support for technical issues and maintenance, which reduces the risk of extended outages resulting from IT asset failures. Timely replacement of end-of-life assets also helps to avoid cost increases associated with extending vendor services agreements beyond the vendor's stated end-of-support date. Replacement assets are selected to meet expected capacity needs for the life of the asset.

Cost estimates for the planned mitigation programs are shown in Tables 3-9 and 3-10. The values represent costs to mitigate IT Asset Failure risk overall, not just the cross-cutting impact IT Asset Failure has on RAMP risks.

TABLE 3-9
MITIGATION COST ESTIMATES
2024-2030 EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Mitigation ID	Mitigation Name	MWC	2024	2025	2026	2027	2028	2029	2030	Total
1	ITAFL-M007	Lifecycle Existing Assets – Network Technology	JV	$1,200	$1,250	$1,300	$1,350	$1,400	$1,450	$1,500	$9,450
2	ITAFL-M008	Add Resiliency/Redundancy – Network Technology	JV	–	–	–	–	–	–	–	–
3	ITAFL-M009	Upgrade IT Common Facilities Infrastructure	JV	–	–	–	–	–	–	–	–
4	ITAFL-M010	Network 20/20	JV	300	500	–	–	–	–	–	800
5	ITAFL-M011	IGP Communication Infrastructure Upgrades	JV	400	400	400	–	–	–	–	1,200
6	ITAFL-M013	Lifecycle Existing Assets – Applications/Application Components	JV	2,200	2,200	2,500	2,000	1,500	1,500	1,500	13,400
7		Total		$4,100	$4,350	$4,200	$3,350	$2,900	$2,950	$3,000	$24,850

Note: The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

TABLE 3-10
MITIGATION COST ESTIMATES
2024-2030 CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Mitigation ID	Mitigation Name	MWC	2024	2025	2026	2027	2028	2029	2030	Total
1	ITAFL-M7	Lifecycle Existing Assets – Network Technology	2F	$52,000	$60,000	$110,000	$110,000	$130,000	$140,000	$150,000	$752,000
2	ITAFL-M8	Add Resiliency/ Redundancy – Network Technology	2F	5,000	5,250	5,500	5,750	6,000	6,500	6,750	40,750
3	ITAFL-M9	Upgrade IT Common Facilities Infrastructure	2F	5,000	5,150	2,600	2,700	2,700	2,800	2,900	23,850
4	ITAFL-M10	Network 20/20	2F	79,000	75,000	–	–	–	–	–	154,000
5	ITAFL-M11	IGP Communication Infrastructure Upgrades	2F	29,000	35,000	35,000	35,000	–	–	–	134,000
6	ITAFL-M13	Lifecycle Existing Assets – Applications/Application Components	2F	45,000	55,000	45,000	35,000	25,000	25,000	25,000	255,000
7		Total		$215,000	$235,400	$208,100	$188,450	$163,700	$174,300	$184,650	$1,359,600

Note: The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

b. Mitigations With CBRs

Given the complexities of allocating the CCF costs and benefits of an IT asset failure mitigation between RAMP and non-RAMP risk events, CBRs for the mitigations are not presented. PG&E continues to work on these issues and expects to share CBRs for IT Asset Failure mitigation programs in a future report or proceeding

H. Physical Attack

1. Overview

Physical Attack is defined as an attack on PG&E physical assets or personnel, that could result in damage to property, operational and other business impacts, or injury/fatality. Physical attacks are increasing as evidenced by the surge in threats and attacks to our coworkers and recent physical security incidents at various utilities in the U.S.[13]

PG&E manages the Physical Attack risk in its Corporate Security organization. Activities include assessing and mitigating physical security risks related to employees, contractors, physical assets, facilities and critical infrastructure. The Corporate Security organization is responsible for emergency response, incident management and collaborating with local management on reducing physical security vulnerabilities and risk mitigations.

2. Modeling

Physical Attack preparedness impacts the likelihood of a risk event and includes both attacks against a person and attacks on a PG&E facility or asset.

To model this CCF, PG&E evaluates external and internal threat data, internal incidents, external attack events and trends nationally on similar facilities. Additionally, PG&E leverages an internal database identifying each physical attack on a PG&E asset related to electric distribution overhead assets, electric transmission assets, power generation and gas

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13 Magnus Lofstrom and Brandon Martin, Public Policy Institute of California, Crime Trends in California (Oct. 2023), available at: <https://www.ppic.org/publication/crime-trends-in-california/> (accessed May 3, 2024).

distribution and transmission assets. To model physical attacks related to PG&E's dam facilities, PG&E relied on industry data and SME insight.[14]

3. Impacts to the 2024 RAMP Risks

Physical Attack impacts at least 10 RAMP risks. PG&E is continuing to evaluate the impact that Physical Attack has on RAMP risks and expects to present new findings in a future report or proceeding.

Table 3-11 below maps the Physical Attack CCF to the applicable RAMP risks.

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[14] Please see Exhibit (PG&E-5), Ch. 1, Section B.1.a.4 for more details.

TABLE 3-11
CCF SUMMARY: PHYSICAL ATTACK

Line No.	RAMP Risk	Modeling Method[(a)]	Risk Frequency, Percentage (Events/Year)	Percent of Risk
1	Contractor Safety Incident	Driver (Extracted from Existing)	0.1 percent (0.04)	0.1 percent
2	Cybersecurity Risk Event	Embedded	[(b)]	--
3	Employee Safety Incident	Driver (Extracted from Existing)	0.3 percent (1)	0.1 percent
4	Electric Transmission Systemwide Blackout	Driver (Extracted from Existing)	8 percent (0.0005)	8 percent
5	Failure of Electric Distribution Overhead Assets	Driver (Extracted from Existing)	0.1 percent (39)	0.1 percent
6	Failure of Distribution Underground Assets	Driver (Extracted from Existing)	0.4 percent (12)	0.4 percent
7	Large Overpressure Event Downstream of Gas Measurement and Control Facility	–	[(b)]	--
8	Large Uncontrolled Water Release (Dam Failure)	Driver (Added Frequency)	0.03 percent (0.00001)	0.1 percent
9	Loss of Containment on Gas Distribution Main or Service	Driver (Extracted from Existing)	0.02 percent (6)	0.02 percent
10	Loss of Containment on Gas Transmission Pipeline	Driver (Extracted from Existing)	0.3 percent (0.01)	0.09 percent
11	Public Contact with Intact Energized Electrical Equipment	Driver (Extracted from Existing)	21 percent (1.4)	21 percent
12	Wildfire	Driver (Extracted from Existing)	0.1 percent (1)	0.1 percent

(a) The modeling method(s) employed to quantify the CCF. Where the CCF is mapped to the risk event but the modeling method has not yet been established and/or implemented, the entry is blank. See Section C.1 for method explanations.

(b) The CCF influences the baseline risk, but risk from the CCF has not been explicitly quantified.

<u>Employee Safety Incident</u>

A physical attack is a driver that can lead to any of the outcomes associated with an Employee Safety Incident.

<u>Failure of Electric Distribution Overhead Assets</u>

Physical Attack can increase the likelihood of this risk event. It occurs when third parties tamper with Distribution Overhead assets resulting in outages.

Large Uncontrolled Water Release

While a physical attack on a hydroelectric dam could potentially cause a risk event, there are no instances of this occurring in the U.S. Physical Attack is not a significant driver to the risk event.

Loss of Containment on Gas Distribution Main or Service

A physical attack could cause a loss of containment on Gas Distribution Main or Service event. Fewer than one percent of about 30,000 loss of containment events on gas distribution main or service that are expected to occur annually are attributed as physical attack or intentional damage.

Loss of Containment on Gas Transmission Pipeline

Physical Attack could cause the Loss of Containment on Gas Transmission Pipeline. Fewer than one percent of the loss of containment events on gas transmission pipeline that are expected to occur annually are attributed as physical attack or intentional damage.

Contractor Safety Incident

A physical attack is a driver that can lead to any of the outcomes associated with a Contractor Safety Incident.

Wildfire

A physical attack could lead to asset failures that can lead to an outage or ignition.

Electric Transmission Systemwide Blackout

A physical attack could cause a grid emergency.

Failure of Distribution Underground Assets

Physical attack could lead to outages on the Distribution Underground Assets network and financial damages.

Cybersecurity Risk Event

Physical attack could lead to access to assets and our networks and enable a potential Cyber Security incident.

Public Contact with Intact Energized Electrical Equipment

Vandalism and theft/attempted theft can potentially lead to contact with intact energized electrical equipment and is included as a risk driver for the PCEEE risk

4. Changes Since the 2020 RAMP

Physical Attack was not a 2020 RAMP risk and presented as a CCF. In the 2020 RAMP, Corporate Security had two mitigation domains, Prevent and Detect and will continue with them. We are evaluating whether physical attack should be considered a stand-alone risk. As we mature the program, we will explore and expand to five mitigation domains—Deter, Detect, Deny, Delay, and Defend—to better align with the Company's overall Corporate Security strategy. We are further strengthening our programs to mitigate risks at our critical infrastructure. This includes more threat vulnerability assessments to identify security gaps at our critical sites. Also, we are developing a critical facility tier ranking methodology to prioritize risk mitigation work at these facilities. As crime continues grow and poses a risk to our coworkers, we are looking at different ways to ensure they are feeling secure and safe in their working environments. Since relocating our headquarter to Oakland, we have made significant security measures to address safety concerns from our coworkers and greater community. We have collaborated with three major Oakland companies on a security enhancement program to improve public safety while keeping our coworkers safe. In addition to improving safety in the Oakland community, to keep our field-based coworker safe from any threats and be able to perform their work, we have embedded Corporate Security resources escorting them to their respective job sites.

5. 2024-2030 Controls and Mitigations

a. Planned Work

PG&E has developed its detailed Corporate Security project plan for 2024. These Corporate Security projects are designed to mitigate the Physical Attack risk. The projects are aligned to Prevent and Detect categories.

- **PHYSA-M001 – Prevent:** Activities designed to reduce the likelihood of a physical attack. These activities limit the impact of security risk-based events, reducing both frequency and consequence.

In 2024, PG&E is planning to have majority of the mitigation projects primarily aligned to the Prevent domain to reduce risk. One of the Prevent projects planned is to enhance security hardening at our critical sites, which includes deploying Mobile Surveillance Units to manage risks against intrusions and physical attacks.

- **PHYSA-M002 – Detect:** Activities designed to timely identify and respond to physical attack incidents. In 2024, one of the Detect projects PG&E is enhancing our Security Control Center (SCC) to increase the efficiency and ability to monitor and address risks at our facilities. In 2023, we have started and completed phase 1 of the SCC modernization.

Between 2024 and 2030, PG&E will continue to implement the two mitigations: M1: Prevent and M2: Detect. The individual projects aligned to these two domains will be implemented and continue to be developed.

In addition to the mitigations planned for 2024-2030, PG&E will also implement a series of controls to manage Physical Attack risk. These controls include:

- **Control 1 – Physical Security**: Responsible for emergency response, incident management, and collaborating with local management on physical security vulnerabilities and incident management;
- **Control 2 – Security Asset and Technology**: Design and implement technology solutions to mitigate physical security risks;
- **Control 3 – Corporate SCC**: Monitor and respond to physical security alarms, and provide security office deployment, and physical access control management. We are continuing to modernize the SCC to make it more effective and efficient to better monitor and respond to security incidents; and
- **Control 4 – Investigations**: Conducts internal and external investigations of criminal activities and employee misconduct. Responsibilities include maintaining law enforcement and industry security liaison relationships to build in-house intelligence, and identifying, evaluating, and mitigating threats and vulnerabilities.

Other services include enterprise-wide training (e.g., active shooter, workplace violence awareness). We are also piloting virtual reality (VR) technology led training to provide further security awareness.

b. Mitigations With CBRs

Cost estimates, risk reduction values, and CBRs for the planned mitigation work are shown in Tables 3-12, 3-13, and 3-14 below. Risk reduction and CBRs for Physical Attack mitigations reflect only RAMP risks rather than all risks on PG&E's CRR that map to this CCF. As such, these values will not reflect the full benefits of the programs.

TABLE 3-12
MITIGATION COST ESTIMATES
2024-2030 EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Mitigation ID	Mitigation Name	MWC	2024	2025	2026	2027	2028	2029	2030	Total
1	PHYSA-M001	Prevent	KZ	$904	$931	$959	$987	$1,017	$1,048	$1,079	$6,924
2	PHYSA-M002	Detect	KZ	147	151	156	161	165	170	175	1,126
3		Total		$1,051	$1,082	$1,115	$1,148	$1,182	$1,218	$1,254	$8,050

Note: The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

TABLE 3-13
MITIGATION COST ESTIMATES
2024-2030 CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Mitigation ID	Mitigation Name	MWC	2024	2025	2026	2027	2028	2029	2030	Total
1	PHYSA-M001	Prevent	3N	$11,261	$11,598	$11,946	$12,305	$12,674	$13,054	$13,446	$86,284
2	PHYSA-M002	Detect	3N	1,698	1,749	1,801	1,855	1,911	1,968	2,027	13,010
3		Total		$12,959	$13,347	$13,748	$14,160	$14,585	$15,022	$15,473	$99,294

Note: The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

TABLE 3-14
CBR AND RISK REDUCTION: PHYSICAL ATTACK – ALL MITIGATIONS

Line No.	Mitigation	Aggregated		Applied to RAMP Risk
		CBR[a]	Risk Reduction (NPV)[b]	Risk Reduction (NPV)[b]
1	M1: Prevent	< 0.1	3.7	
2	M2: Detect	0.2	1.5	
3	Applicable RAMP Risk			
4	Electric Transmission System-Wide Blackout			1.8
5	Contractor Safety Incident			<0.01
6	Cybersecurity Risk Event			2.4
7	Failure of Electric Distribution Overhead Assets			0.1
8	Failure of Electric Distribution Underground Assets			0.1
9	Employee Safety Incident			0.04
10	Large Uncontrolled Water Release (Dam Failure)			<0.01
11	Loss of Containment on Gas Distribution Main or Service			<0.01
12	Loss of Containment on Gas Transmission Pipeline			<0.01
13	Public Contact with Energized Electric Equipment			0.7
14	Total		5.2	5.2

(a) See Exhibit (PG&E-2), WP RM-CCF, CC-PHYSA-1 included in the source document modeling package for information used to calculate the CBR.

(b) NPV uses a base year of 2023.

I. Records and Information Management

1. Overview

The risk of not having an effective RIM Program is not having information readily available when needed or information that is not complete or accurate, which can have safety, reliability, and financial consequences.

All PG&E employees and non-employee workers are responsible for managing data, information, and records effectively in accordance with PG&E standards administered by the Information and Records Governance organization. The RIM Program is an integral part of PG&E's efforts to further strengthen our safety culture and to provide safe and reliable gas and electric service to customers in support of the stand that everyone and everything is always safe. PG&E'S RIM risk decreases as RIM maturity improves through the promotion of consistent records and information processes and controls, improving compliance and operational efficiency.

PG&E achieved Level 3 of ARMA International's[15] Information Governance Maturity Model (IGMM) by 2022. IGMM Level 3 was deemed essential, the minimum required for effective information governance, based on established industry standards, best practices, and legal/regulatory requirements. The Information and Records Governance organization is making updates to the Information Governance Maturity Framework and will continue to organize mitigations and controls according to maturity characteristics.

2. Modeling

RIM can impact the likelihood or consequence of a risk event or both. The impact to the likelihood of a risk event is when a record does not exist, is missing, is not readily available, or is incorrect. The risk model considers whether RIM issues such as missing inspections records, incorrect construction documents, or asset information that is difficult to find, has the potential to increase the likelihood of a risk event occurring.

RIM issues can also impact the financial consequence of a risk event. To model the financial consequences, PG&E analyzed the potential financial consequences related to identifying and producing records after an event. To account for this financial consequence PG&E adds a RIM multiplier that is applied to each of the risks that have identified where RIM impacts the frequency or the consequence.

3. Impacts to the 2024 RAMP Risks

RIM impacts 11 out of 12 RAMP risks. Table 3-15 below maps the RIM CCF to the applicable RAMP risks.

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[15] ARMA International was previously known as the "Association of Records Managers and Administrators (ARMA)." ARMA International is a membership association for information management and information governance professionals.

TABLE 3-15
CCF SUMMARY: RIM

Line No.	RAMP Risk	Modeling Method[a]	Risk Frequency, Percentage (Events/Year)	Percent of Risk
1	Contractor Safety Incident	Consequence Multiplier	--	[b]
2	Cybersecurity Risk Event	Consequence Multiplier	--	[b]
3	Employee Safety Incident	Driver (Extracted from Existing) / Consequence Multiplier	1.3 percent (4.9)	[b]
4	Failure of Electric Distribution Overhead Assets	Driver (Extracted from Existing) / Consequence Multiplier	0.0 percent (4.67)	[b]
5	Failure of Electric Distribution Underground Assets	Driver (Extracted from Existing) / Consequence Multiplier	0.6 percent (0.07)	[b]
6	Large Overpressure Event	Driver (Extracted from Existing) / Consequence Multiplier	5 percent (0.3)	[b]
7	Large Uncontrolled Water Release (Dam Failure)	Consequence Multiplier	--	[b]
8	Loss of Containment on Gas Distribution Main or Service	Driver (Extracted from Existing) / Consequence Multiplier	0.8 percent (222)	[b]
9	Loss of Containment on Gas Transmission Pipeline	Driver (Extracted from Existing) / Consequence Multiplier	0.6 percent (0.02)	[b]
10	Electric Transmission Systemwide Blackout	Consequence Multiplier	--	[b]
11	Wildfire	Consequence Multiplier	--	[b]

(a) The modeling method(s) employed to quantify the CCF. Where the CCF is mapped to the risk event but the modeling method has not yet been established and/or implemented, the entry is blank. See Section C.1 for method explanations.

(b) Percent of Risk was not calculated when the CCF impacts consequences of risk events.

4. Changes Since the 2020 RAMP

In the 2020 RAMP, PG&E presented seven mitigations and five controls it planned to implement during the 2020-2026 period. PG&E reported on the progress of the mitigations and controls in its 2023 General Rate Case (GRC).[16]

16 A.21-06-021, Exhibit (PG&E-7). Ch.7, pp. 7-8 to 7-26.

Of the seven mitigations PG&E proposed in its 2020 RAMP for the 2020-2026 period,[17] three mitigations were implemented during that period and have become ongoing controls. The mitigation numbers referred to herein are the numbers assigned in the 2020 RAMP.

- Compliance-Related Mitigation (M3C) with the offline data remediation in 2020;
- Availability-Related Mitigations (M6C) by completing the external, mobile, and offline access for Documentum in 2023; and
- Disposition Related Mitigations by establishing a governance model and transitioning to operational implementation in 2021 (M10C)

Four mitigations will continue to be implemented during the 2023-2026 period.

- M4C: Retention-Related Mitigations;
- M7C & M7E: Implement RIM Governance for Content in Unstructured Data Repositories (while the Gas OII work completed in 2022 with SharePoint, Documentum, and Shared Drives, work remains in those repositories for the remainder of the Company);
- M11 & M11A: Integrity Related Mitigations; and
- M13C&D: Implement RIM Governance for Content in Structured Data Repositories.

One control has been added to the five existing controls, as described in the 2020 RAMP to manage records and information risk.[18] That new control is Availability Related Controls (C6) with the implementation of risk-based updates of the records inventory and business process improvements.

Work within two controls, Availability and Protection, have been completed or transitioned to other controls since 2020 RAMP.

- Availability: After the nitrate negatives were moved to a fire-safe container and scanned to retain them digitally, the negatives were disposed of and the container was retired in 2022;

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[17] A.20-06-012, PG&E's 2020 RAMP Report, p. 20-AtchA-55, Table 25.

[18] A.20-06-012, PG&E's 2020 RAMP Report, p. 20-AtchA-53.

- Protection: System retirement efforts were incorporated into the ongoing disposition work within the Disposition control in 2023;
- Protection: Physical records assessments and cleanups were completed in 2021 and have been incorporated into health checks (Compliance) and decommissioning efforts (Protection);
- Protection: Emergency response documentation was completed in 2022.

5. 2024-2030 Controls and Mitigations

PG&E is managing six individual RIM mitigations. These six mitigations are combined in the risk model into a single RIM mitigation as a CCF multiplier.

a. Planned Work

The RIM mitigations that PG&E will implement during 2024-2030 are:

- **RECIM-M04C – Records Retention Related Mitigations**: These mitigations involve maintaining records and non-records for an appropriate time, accounting for legal, regulatory, fiscal, and operational requirements.
- **RECIM-M007– Implement RIM Governance for Content in Unstructured Data Repositories**: Implementing metadata, retention controls and retention trigger events in applications such as e-mail, SharePoint, and file shares to support efficient and accurate retrieval of needed information and the application of automated retention and disposition of non-records.
- **RECIM-M011 – Records Integrity Related Mitigations**: These mitigations improve the integrity of records and information to support authenticity and reliability.
- **RECIM-M013 – Implement RIM Governance for Content in Structured Data Repositories**: This mitigation implements retention controls and identifies retention trigger events in database applications such as SAP, Customer Care and Billing, and other systems to dispose of records and information that are no longer needed.

PG&E will use the six controls to manage records and information risk during this RAMP period: RECIM-C001 – Records Accountability Related Controls; RECIM-C002 – Records Transparency Related Controls; RECIM-C003 – Records Compliance Related Controls; RECIM-C004 – Records Retention Related Controls; RECIM-C005 Records Protection Related Controls; and RECIM-C006 Records Availability Related Controls.

b. Mitigations With CBRs

Cost estimates, risk reduction values, and CBRs for the planned mitigation work are shown in Tables 3-16, 3-17, 3-18, and 3-19 below. The values represent costs to mitigate the RIM risk overall, not just the cross-cutting impact RIM risk has on other RAMP risks.

TABLE 3-16
CONTROL COST ESTIMATES
2024-2030 EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Control ID	Control Name	2024	2025	2026	2027	2028	2029	2030	Total
1	RECIM-C001	Records Accountability Related Controls	$1,159	$1,181	$1,000	$1,037	$1,073	$1,110	$1,146	$7,706
2	RECIM-C002	Records Transparency Related Controls	1,250	1,251	1,237	1,279	1,322	1,379	1,406	9,124
3	RECIM-C003	Records Compliance Related Controls	1,007	1,055	970	1,041	1,151	1,190	1,229	7,643
4	RECIM-C004	Records Retention Related Controls	3,204	3,314	2,523	2,498	2,373	2,398	2,423	18,733
5	RECIM-C005	Records Protection Related Controls	721	742	828	848	818	838	858	5,653
6	RECIM-C006	Records Availability Related Controls	466	488	575	596	617	638	659	4,042
7	RECIM-C007	Records Disposition Related Controls	693	726	822	852	515	532	550	4,689
8	RECIM-C008	Records Integrity Related Controls	258	350	315	170	176	182	188	1,641
9		Total	$8,759	$9,107	$8,270	$8,321	$8,045	$8,268	$8,460	$59,230

Note: The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

TABLE 3-17
MITIGATION COST ESTIMATES
2024-2030 EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Mitigation ID	Mitigation Name	2024	2025	2026	2027	2028	2029	2030	Total
1	RECIM-M04C	Records Retention Related Mitigations	$351	$326	$127	$28	–	–	–	$833
2	RECIM-M007	Implement RIM Governance for Content in Unstructured Data Repositories	1,988	2,507	1,826	263	272	281	290	7,427
3	RECIM-M011	Records Integrity Related Mitigations	539	353	255	257	–	–	–	1,404
4	RECIM-M013	Implement RIM Governance for Content in Structured Data Repositories	687	1,274	1,288	1,298	309	319	330	5,505
5		Total	$3,566	$4,461	$3,495	$1,846	$581	$600	$620	$15,169

Note: The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

TABLE 3-18
MITIGATION COST ESTIMATES
2024-2030 CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Mitigation ID	Mitigation Name	2024	2025	2026	2027	2028	2029	2030	Total
1	RECIM-M04C	Records Retention Related Mitigations	$653	$674	$660	–	–	–	–	$1,987
2	RECIM-M007	Implement RIM Governance for Content in Unstructured Data Repositories	5,586	1,523	3,634	–	–	–	–	10,743
3	RECIM-M013	Implement RIM Governance for Content in Structured Data Repositories	–	–	1,000	1,000	–	–	–	2,000
4		Total	$6,239	$2,197	$5,294	$1,000	–	–	–	$14,730

Note: The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

TABLE 3-19
CBR AND RISK REDUCTION: RIM- ALL MITIGATIONS AND CONTROLS

Line No.	RIM Mitigations and Controls (2027-2030 Program)	CBR[(a)]	Risk Reduction (NPV) $M[(b)]
1	Records Retention Related Mitigations	14	0.3
2	Records Availability Related Mitigations	–	–
3	Implement Records and Information Management Governance for Content in Unstructured Data Repositories	123	93
4	Records Integrity Related Mitigations	2.6	0.5
5	Implement Records and Information Management Governance for Content in Structured Data Repositories	5.1	14
6	Records Accountability Related Controls	0.5	1.4
7	Records Transparency Related Controls	0.4	1.4
8	Records Compliance Related Controls	0.2	0.7
9	Records Retention Related Controls	1.3	9.0
10	Records Protection Related Controls	3.1	7.3
11	Records Availability Related Controls	0.4	0.8
12	Records Disposition Related Controls	3.7	6.3
13	Records Integrity Related Controls	1.6	0.8
14	Total	5.1	136

(a) See Exhibit (PG&E 2), WP RM CCF, CC RECIM 1 included in the source document modeling package for information used to calculate the CBR.

(b) NPV uses a base year of 2023.

J. Seismic

1. Overview

Seismic events can be a significant driver of failure in FA assets. They contribute to the likelihood of asset failure events and to the associated safety, reliability, and financial consequences of those events.

PG&E's service territory is in an active seismic region and as such PG&E assets from all FAs are subjected to potentially damaging ground shaking and related ground failure that ranges from minor to catastrophic from a single event. Damaging effects may occur without warning over a large geographic area and impact PG&E's ability to serve its customers and respond to the event. The greater San Francisco (SF) Bay Area is considered to have the highest seismic risk in PG&E's service territory due to the existence of many active faults located in highly-populated urban areas with dense PG&E infrastructure. Extensive damage to non-PG&E

infrastructure and supporting business and suppliers will impact restoration efforts.

The PG&E Geosciences Department (Geosciences) is responsible for monitoring earthquake events, managing research studies and seismic risk knowledge integration, and developing earthquake hazard and risk models. Geosciences is part of the Wildfire and Emergency Operations organization and provides services across PG&E's FAs and service territory. Geosciences was developed as a department in 1985 as part of the Long-Term Seismic Program (LTSP) focusing on seismic issues at the DCPP. Maintenance of the Geosciences Department and LTSP were established as an operating license commitment for the duration of operation of the DCPP. The initial DCPP-focused mission of Geosciences and the LTSP have been broadened and evolved over time to support the entirety of the PG&E FAs and service territory. Since 2020 Geosciences has been responsible to develop and manage the RAMP seismic cross cutting factor in support of earthquake and geologic hazards risk evaluations for the FAs. Currently Geosciences is involved in and supports geohazard risk assessments efforts across the enterprise and all the FAs including:

- The DCPP and Enterprise LTSP;
- Earthquake notifications and evaluations;
- The Hydro Facility and Dam Safety Program;
- Corporate Real Estate Strategy and Services building seismic assessment and retrofit;
- The Gas Transmission Pipeline Geohazards Program;
- Electric Transmission system facilities and programs;
- Geosciences SME role for the Company EP&R Emergency Operation Center activations and emergency events;
- EP&R CERP earthquake and tsunami annex development and maintenance;
- EP&R earthquake exercise support;
- The EP&R DASH Program development and maintenance for event notification and initial emergency response planning;
- Development of earthquake hazard and risk assessment tools for Enterprise FAs, and;

- Earthquake science and learning from earthquakes ground motion model development and support including collaborations with the United States Geological Survey (USGS), national laboratories, industry working groups and many leading academic institutions advancing the seismic knowledge and implementation for risk reduction.

Focused seismic risk assessment and reduction activities for Enterprise FAs are managed through the Geosciences Integrated Seismic Risk Management Program (ISRMP) that includes application of various tools to quantify seismic risk. The ISRMP enables progressive quantification of seismic hazard. Geosciences uses a tool called System Earthquake Risk Assessment (SERA) to analyze seismic risk. SERA is a commercial platform that has been modified for PG&E's applications to evaluate the geographically distributed electric and gas linear assets. SERA is used by utilities across the western U.S. and Canada, helping to standardize seismic hazard analyses.

The current focus of the ISRMP is to prioritize seismic risk assessment to assets in the greater SF Bay Area and then extend evaluations through the rest of PG&E's service territory. This strategy is informed by the USGS' findings that the seismic hazard and the consequential impact in the SF Bay Area is highest in this region and therefore represents the greatest seismic risk.

2. Modeling

The Seismic CCF impacts both the likelihood of a risk event occurring and the consequences of a risk event. Seismic is a risk driver for the Large Uncontrolled Water Release (Dam Failure), Electric Operations risks, and Loss of Containment on Gas Transmission Pipeline and Distribution Main or Service risks.

For electric and gas risks, PG&E modeled this CCF using the SERA model. SERA is used to evaluate the geographically-distributed electric and gas linear assets. The SERA platform includes fragility models for system components that have been developed from both California-specific and worldwide data from past earthquakes. The platform evaluates system performance from both ground shaking and ground failure (e.g., surface fault rupture, liquefaction, landslides) based on geohazard maps and earthquake scenarios. To assess system performance PG&E models several plausible earthquake scenarios.

PG&E evaluated the likelihood of a seismic event occurring by modeling three plausible earthquake scenarios in the SF Bay Area. The three scenarios are on the San Andreas, Hayward, and Rogers Creek faults. The consequence of a seismic event is evaluated in terms of gas and electric asset performance.

Outputs from the modeling included the frequencies and the safety, financial and reliability consequences of risk events resulting from asset failures due to the seismic event. PG&E also considered the compounding disruption due to the simultaneous failure of electric and gas assets within each tranche in the case of a seismic event. Tranche-level risk scores are calculated based on the cumulative safety, financial or reliability consequences within each tranche as a result of the seismic event. Utilizing the non-linearity of the Risk Attitude Function, seismic risk scores reflect risk aversion against severe seismic outcomes from simultaneous asset failures.

3. Impacts to the 2024 RAMP Risks

Seismic hazard impacts seven RAMP risks. A seismic event can result in safety, reliability, and financial consequences. Tables 3-20 and 3-31 below map the Seismic CCF to the applicable RAMP risks.

TABLE 3-20
CCF DRIVERS SUMMARY: SEISMIC

Line No.	RAMP Risk	Modeling Method[(a)]	Risk Frequency Percentage (Events/Year)	Percent of Risk
1	Electric Transmission System-wide Blackout	Driver (Extracted from Existing)	1.3 percent (<0.01)	1.3 percent
2	Failure of Electric Distribution Overhead Assets	Driver (Added Frequency)/Outcome	0.15 percent (43)	8.7 percent
3	Failure of Electric Distribution Underground Assets	Driver (Added Frequency)/Outcome	1.3 percent (36)	8.4 percent
4	Large Uncontrolled Water Release (Dam Failure)	Driver (Added Frequency)	36 percent (0.01)	37 percent
5	Loss of Containment on Gas Distribution Main or Service	Driver (Added Frequency)/Outcome	0.29 percent (84)	1.4 percent
6	Loss of Containment on Gas Transmission Pipeline	Driver (Added Frequency)/Outcome	5.5 percent (0.2)	23 percent
7	Wildfire	Driver (Added Frequency)/Outcome	<0.01 percent (<0.01)	0.2 percent

(a) The modeling method(s) employed to quantify the CCF. Where the CCF is mapped to the risk event but the modeling method has not yet been established and/or implemented, the entry is blank. See Section C.1 for method explanations.

TABLE 3-21
CCF OUTCOME SUMMARY: SEISMIC

Line No.	RAMP Risk	Outcome	Percent Frequency	Percent Risk
1	Failure of Electric Distribution Overhead Assets	Asset Failure/Seismic Scenario	0.15 percent	8.7 percent
2	Failure of Electric Distribution Underground Assets	Asset Failure/Seismic Scenario	1.3 percent	8.4 percent
3	Loss of Containment on Gas Distribution Main or Service	Major – Seismic	<0.01 percent	0.52 percent
4	Loss of Containment on Gas Distribution Main or Service	Minor – Seismic	0.29 percent	0.93 percent
5	Loss of Containment on Gas Transmission Pipeline	Seismic – Rupture	4.7 percent	23 percent
6	Loss of Containment on Gas Transmission Pipeline	Seismic – Leak	0.76 percent	0.015 percent
7	Wildfire	Seismic – Non-Red Flag Warning (RFW) – Office of Energy Infrastructure Safety (OEIS) Catastrophic – Destructive Fires	<0.01 percent	0.075 percent
8	Wildfire	Seismic – Non-RFW – OEIS Non-Catastrophic – Destructive Fires	<0.01 percent	0.008 percent
9	Wildfire	Seismic – RFW – OEIS Catastrophic - Destructive Fires	<0.01 percent	0.57 percent
10	Wildfire	Seismic – RFW – OEIS Non-Catastrophic – Destructive Fires	<0.01 percent	0.007 percent

Large Uncontrolled Water Release (Dam Failure)

Seismic is a risk driver of the Large Uncontrolled Water Release risk event and accounts for 37 percent of the total risk.

Loss of Containment on Gas Distribution Main or Service and Loss of Containment on Gas Transmission Pipeline

The seismic CCF is considered a driver for these risk events. Seismic risk accounts for 23 percent of the Gas Transmission risk and 1.4 percent of the Gas Distribution risk.

Failure of Electric Distribution Overhead Assets, Failure of Electric Distribution Underground Assets, Electric Transmission System-wide Blackout and Wildfire

Seismic is a CCF for the Failure of Electric Distribution Overhead Assets, Failure of Electric Distribution Underground Assets, Electric Transmission System-wide Blackout, and Wildfire risks. The seismic risk accounts for 8.7 percent of the Failure Electric Distribution Overhead Assets risk, 8.4 percent of the Failure of Electric Distribution Underground Assets risk, 1.3 percent of the Electric Transmission System-wide Blackout risk, and 0.2 percent of the Wildfire risk.

PG&E will continue conducting seismic risk evaluations for all RAMP risks and, as appropriate, will also conduct seismic risk evaluations for non-RAMP Enterprise risks as well.

4. Changes Since the 2020 RAMP

PG&E has updated how we consider simultaneous asset failure following an earthquake by using a non-linear Risk Attitude Function. PG&E has also updated our Electric asset inventory and fragilities.

In the 2020 RAMP, PG&E used a consequence multiplier for seismic events to incorporate the higher concentration of regional asset failure following an earthquake compared to a routine asset failure. This multiplier captures the increase in severity of an outcome in the model. In the 2024 RAMP, PG&E considered this compounding disruption due to the simultaneous failure of electric and gas assets within each tranche by utilizing the risk averse Risk Attitude Function. Instead of using consequence multipliers, in the 2024 RAMP consequences are calculated based on the total number of failures at each tranche (expected to occur at the same time after an earthquake). Therefore, tranche-level risk scores are calculated based on the cumulative safety, financial or reliability consequences within the tranche due to the seismic event. As such, seismic risk scores properly reflect the severity of seismic outcomes with multiple simultaneous asset failures.

PG&E has updated our Electric asset inventory to reflect assets as of 2022. Electric asset inventory updates include Substation, Transmission Line, and Distribution Line. The updates were performed by Substation field walkdowns in 2022 and updates from our 2022 Transmission Line and Distribution Line GIS data.

Electric asset fragilities have been updated as well. Substation asset fragilities were updated based upon observed earthquake performance and assessment of seismic qualification reports for substation equipment. Transmission Line asset fragilities for 115 kilovolts lattice towers were updated based upon post-buckling structural analyses performed in 2021. Distribution Line asset fragilities were updated based upon observed earthquake performance (2019 Ridgecrest, 2022 Ferndale).

5. 2024-2030 Controls and Mitigations

a. Planned Work

The ISRMP started in 2019 to assess the seismic hazard and seismic risk more consistently for all FAs. PG&E will focus its seismic risk mitigation efforts in the SF Bay Area for electric and gas assets. Going forward, the ISRMP will develop and maintain seismic risk quantifications by focusing on key elements such as:

- Seismic source characterization, regional geology;
- Site specific and distributed system ground motion models;
- Ground failures such as landslide, liquefaction and fault crossings;
- Asset inventory and fragilities to quantify seismic risk; and
- Logic modeling developments/enhancements.

This program is informed by core seismic research performed in the LTSP that has been successfully used at the DCPP for more than 30 years. Seismic risk analysis for gas and electric assets includes three viable and severe scenarios: the Hayward Fault at the foot of the East Bay hills; the San Andreas Fault that extends through the SF Peninsula; and the Rogers Creek Fault that extends from the Bay through Santa Rosa. Future updates will expand to consider total hazard from other faults.

During the 2024 RAMP period Geosciences worked with FA asset owners and risk managers to develop the means to consistently quantify seismic risk and to inform risk mitigations tailored to those FA assets. To develop the seismic mitigations for the different asset types, Geosciences and the FA teams will work together to analyze asset failure modes and asset-specific risks.

PG&E will also continue to update and refine information in SERA to address uncertainties in modeling results based on earthquake experience learnings, research, and collaborations with leading earthquake academia and government agencies, including the California Energy Commission. This continual improvement process will lead to more granular system performance modeling to better estimate damages from future earthquakes and focus mitigations on areas and components of highest risk.

In addition to system damage assessment tools such as SERA, PG&E has also developed a proprietary earthquake response tool called DASH. The DASH tool collects seismic instrument records and ground shaking maps from the USGS to evaluate and notify of potential system impacts within a 15 to 30-minute timeframe after an earthquake. The DASH tool compares ground shaking maps against simplified damage models specific to each FA and produces reports of potential damage that the business uses to inform and prioritize inspections and responses. The DASH tool also includes a continuous improvement element that includes annual updates of infrastructure inventories and tool maintenance/reliability improvements.

b. Mitigations With CBRs

Seismic risk assessment is a collaborative process between Geosciences and the FAs. The Geosciences ISRMP is a foundational program that quantifies the potential seismic risk for operations assets. The FAs develop the mitigations to address this risk.

While the ISRMP is not proposing seismic mitigations in the 2024 RAMP, PG&E will maintain its LTSP and ISRMP Program for assessing seismic risk.

PACIFIC GAS AND ELECTRIC COMPANY
RISK ASSESSMENT AND MITIGATION PHASE
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RAMP RISK SELECTION

A. Introduction

In this chapter, Pacific Gas and Electric Company (PG&E or the Company or the Utility) describes the process for selecting the safety risks evaluated within this Risk Assessment and Mitigation Phase (RAMP) Report in accordance with the Risk-Based Decision-Making Framework (RDF) outlined in the RDF Proceeding Phase II Decision, including hosting a public workshop to introduce the proposed RAMP risks. This chapter will also discuss how PG&E addressed feedback provided at the public workshop and compares PG&E's 2024 RAMP risk selection with the risks included in its 2020 RAMP report.

B. Risk Identification and the Enterprise Risk Register (Step 1B of the RDF)

As directed in the RDF, the Utility's Enterprise Risk Register (ERR) is the starting point for selecting risks to be evaluated in RAMP.

Following the issuance of the RDF Proceeding Phase II Decision in December 2022, PG&E began refining its risk assessment methodology and risk models to incorporate the principles of the Cost-Benefit Approach. This process included evaluating, selecting, and refining the consequence attributes, and Risk Attitude Function discussed in Exhibit (PG&E-2), Chapter 2. PG&E applied these principles to its ERR, known internally as the Corporate Risk Register (CRR), which contained 32 risk events at the end of 2023.

C. Risk Assessment, Risk Ranking, and Risk Selection for RAMP Evaluation (Steps 2A and 2B of the RDF)

Of those risk events on the 2023 CRR, 27 had a Safety Risk Score greater than zero. The RDF requires utilities, using the Cost-Benefit Approach, to: (1) "compute a monetized Safety Risk Value using only the Safety Attribute" for those risks with a safety risk component; and (2) "[f]or the top 40 [percent] of ERR risks with a Safety Risk Value greater than zero dollars, … compute a monetized Risk Value using at least the Safety, Reliability and Financial

Attributes."[1] Using the RDF, PG&E identified 11 risks—slightly more than 40 percent—with a Safety Risk Value that required further analysis and computation of a monetized Risk Value (Total Risk Value) for purposes of determining the preliminary risks to be evaluated in RAMP. PG&E, at its discretion, also included the risk event with the twelfth-highest Safety Risk Value: "Failure of Electric Distribution Underground Assets" to its preliminary RAMP risk selection.[2]

Table 4-1 lists the 27 CRR risks with a Safety Risk Value greater than zero, indicates the 12 preliminary RAMP risks, and shows the Safety Risk Values and Total Risk Values for all 27 risks. Values are rounded to the nearest significant digit. These scores represent the model outputs as of January 2024.

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1 D.22-12-027, Appendix A, p. A-10, No. 9.

2 PG&E considers all its safety risks important and, as such, monitors and manages them through its normal course of business.

TABLE 4-1
PG&E'S PRELIMINARY RISK VALUES PRESENTED IN FEBRUARY 7, 2024 PREFILING WORKSHOP

Line No.	Safety Risk Event	Preliminary RAMP Risk	Safety Risk Value ($M)	Total Risk Value ($M)
1	Wildfire with Public Safety Power Shutoff (PSPS) and Enhanced Powerline Safety Settings (EPSS)	X	342	9,737
2	Loss of Containment on Gas Transmission Pipeline	X	140	188
3	Public Contact with Intact Energized Electrical Equipment	X	61	61
4	Electric Transmission Systemwide Blackout	X	59	2,181
5	Failure of Electric Distribution Overhead Assets	X	52	3,275
6	Contractor Safety Incident	X	36	36
7	Employee Safety Incident	X	31	39
8	Cybersecurity Risk Event	X	25	1,026
9	Large Uncontrolled Water Release (Dam Failure)	X	21	438
10	Large Overpressure Event Downstream of Gas Measurement and Control (M&C) Facility	X	20	21
11	Loss of Containment on Gas Distribution Main or Service	X	19	109
12	Failure of Electric Distribution Underground Assets	X	14	745
13	Real Estate and Facilities Failure		11	27
14	Failure of Electric Transmission Overhead Assets		11	640
15	Access Asset Incident		10	10
16	Aviation Occurrence		5	6
17	Motor Vehicle Safety Incident		2	4
18	Failure of Electric Distribution Substation Assets		1	210
19	Loss of Containment on Gas Customer Connected Equipment		1	2
20	Failure of Electric Transmission Underground Assets		1	69
21	Failure of Electric Transmission Substation Assets		1	88
22	Loss of Containment on CNG Station Equipment		1	1
23	Loss of Containment at a Natural Gas Storage Well or Reservoir		1	3
24	Nuclear Core Damaging Event		<1	4
25	Loss of Containment at Gas M&C or Compression and Processing Facility		<1	1
26	Loss of Containment on Liquefied Natural Gas/CNG Portable Equipment		<1	<1
27	Insufficient Capacity to Meet Customer Demand		<1	2

Once the Utility has determined the Preliminary RAMP Risks to be included in the upcoming RAMP report, the RDF requires the utilities to host a public workshop to introduce the proposed RAMP risks and 14 days prior to the workshop, provide parties with a list of the Preliminary RAMP Risks as well as the monetized Safety Risk Value for each risk in the CRR and the monetized Risk Value for the Preliminary RAMP Risks.[3] PG&E served its 2024 RAMP

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3 D.22-12-027, Appendix A, p. A-12, No. 12.

Preliminary Risk List on parties on January 29, 2024 in advance of the February 7, 2024 workshop.[4]

D. Addressing Stakeholder Feedback

1. PG&E's Public Workshops in Advance of the 2024 RAMP Report

As described in Chapter 1, Introduction, PG&E jointly hosted two public workshops with the Safety Policy Division (SPD) in advance of this RAMP Report. The purpose of these workshops was to communicate PG&E's implementation of the RDF and provide an early opportunity to receive feedback from parties. These workshops also allowed parties to hear about PG&E's progress jointly and publicly rather than in separate meetings. In this way, the participating parties continued the cooperative spirit adopted in the RDF proceeding of continuous improvement in risk assessment methodologies.

PG&E's first workshop was held on February 7, 2024. This workshop was held two weeks following the dissemination of PG&E's 2024 RAMP Preliminary Risks list. The purpose of this workshop was "to gather input from SPD, other interested CPUC staff, and interested parties to inform the determination of the final list of risks to be included in the RAMP."[5] In this workshop, PG&E presented the data, assumptions, and bow tie elements for each of the 12 preliminary RAMP risks. PG&E also provided a comparison of the 2020 RAMP risks to the 2024 RAMP preliminary risks.[6]

2. Incorporating Feedback and Changes Since Workshop 1

PG&E received feedback from TURN, SPD and MGRA at the workshop. This section discusses PG&E's responses to the input provided.

a. Inclusion of Failure of Electric Distribution Substation Assets Risk in RAMP

During the workshop, TURN observed that based on PG&E's preliminary results, Safety was a smaller component of some Risk

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[4] See Exhibit (PG&E-2) Workpaper (WP) RM-Select-01 Prefiling Workshop #1 (Feb. 7, 2024).

[5] D.22-12-027, Appendix A, p. A-12, No. 12.

[6] See Exhibit (PG&E-2) WP RM-Select-01 Prefiling Workshop #1 (Feb. 7, 2024).

values than in the 2020 RAMP. TURN pointed out that for Wildfire risk, Safety accounted for 42 percent of the Risk value in the 2020 RAMP but will only account for 3.5 percent in the 2024 RAMP. PG&E noted that the relative changes were primarily driven by the guidance in D.22-12-027 on the application of monetized values for VSL and Reliability. TURN suggested that given this phenomenon, that perhaps RAMP risks should not be based solely on Safety. TURN further requested that PG&E provide the Risk values at the attribute level for all the Risks on PG&E's CRR, not just the preliminary RAMP Risks. On February 9, 2024, PG&E provided the Risk Values for all Risk at the total and attribute level (i.e. Safety, Reliability, Financial and Total), based on both a Risk-Neutral and PG&E's Scaling Function to members on the service lists of A.21-06-012 and R.20-07-013.[7] On February 14, 2024, TURN responded to PG&E recommending that the Failure of Electric Distribution Substation Assets Risk be added to the RAMP risks. TURN's reasons were that its total Risk value of $210 million was higher than the scores of several other risks that PG&E proposed, and it was in the top 10 total Risk values (7th under the Risk Neutral analysis, and 9th under the Risk-Adjusted analysis).

PG&E considered TURN's recommendation and decided not to include Failure of Electric Distribution Substation Assets in the 2024 RAMP. The primary reason is that while the Risk is in the top 10 based on total Risk values as TURN points out, its Safety attribute score ($1.3 million Risk Neutral, $1.5 million Risk-Adjusted) is an order of magnitude lower than the lowest Safety Risk proposed to include in the 2024 RAMP by PG&E (Failure of Electric Distribution Underground Assets; $11.0 million Risk-Neutral value, $13.6 million Risk-Adjusted). On a Safety basis, it ranks 18th of 27 (67th percentile), well outside the top 40 percent of ERR risks with a Safety Risk Value greater than zero dollars. PG&E also notes that $176 million of the $210 million total value comes from Electric Reliability risk. PG&E firmly believes that RAMP should be focused exclusively on Safety, consistent with the

7 See Exhibit (PG&E-2), WP RM-SELECT-2.

position espoused by the Commission in D.14-12-025, "Expanding SB 705's policy of prioritizing safety to include reliability is outside the scope of this proceeding and the S-MAP and RAMP processes adopted in this decision."[8] As to whether the topic of selection should be revisited or not, as suggested by TURN, is an issue that should be evaluated in the Risk OIR, R.20-07-013.

b. Accounting for Real Income Growth in VSL Forecasts

SPD Staff noted that in its determination of future VSL, e.g. VSL for 2027, 2028, etc., PG&E only escalated the base year (2023) VSL by inflation and did not do so for real income growth.

PG&E confirms that in the 2024 RAMP, PG&E did not escalate both the base year values of VSL and Value of Reliability by real income growth for future years, because PG&E had not determined a way to do so consistently across all Attributes. Given the mathematical structure of the ICE 1.0 model and the datedness of the surveys used in the ICE 1.0 model, PG&E was concerned about the reasonableness of applying the same real income escalation rate to the Value of Electric Reliability (in $/CMI) as one would apply to VSL. Therefore, for 2024 RAMP, PG&E did not factor in real income adjustments when escalating the 2023 values of both VSL and Value of Reliability to years beyond 2023. PG&E will follow the development of ICE 2.0 and consult with LBNL staff, as necessary, to determine if a consistent treatment of real income growth across all PG&E's Attributes that can be implemented.

c. Large Overpressure Event Risk as a Separate Risk Model

At the workshop, SPD Staff inquired as to why PG&E considers its large overpressure risk (Large Overpressure Event Downstream of M&C Facility (LRGOP)) separate from its Loss of Containment on Transmission Pipeline (LOCTM) risk. There are several considerations that have influenced this modeling structure.

First, PG&E has structured gas risks such that they are mutually exclusive and aligned with specific gas asset families. One of the reasons that PG&E implemented its gas asset family structure over

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8 D.14-12-025, p. 53, Conclusion of Law 8.

10 years ago was to drive consistency in how PG&E thinks about and addresses risk across its diverse gas assets.

This leads to the second consideration, which is that diversity in asset types leads to diversity and specificity in risk drivers. The drivers that influence the likelihood of large overpressure events are in large part specific to conditions at regulator stations or regulator sets, not downstream pipeline segments. For example, the Equipment-Related risk driver that applies to large overpressure risk is dependent on the type of regulator(s) installed at different station types. Having a risk model dedicated to large overpressure risk allows for the development of tranches in terms of regulating facilities, which is where the large overpressure risk drivers actually occur.

Third, large overpressure risk as defined by the LRGOP risk model is unique in that it involves an event at one location (namely a regulator station or regulator set) that can result in consequences at another location, namely downstream pipeline (transmission or distribution). Risk mitigation programs performed at the level of individual regulator stations or regulator sets have the benefit of protecting the downstream pipeline system, not just individual pipe segments. By having a model that is specific to large overpressure event risk that is structured with exposure and tranches based on number of regulating facilities, it is possible to calculate CBRs for programs that involve risk mitigation at specific station locations (e.g., the installation of secondary overpressure protection).

For these reasons, LRGOP risk is considered in a separate risk model from the gas pipeline risk models. Accordingly, the scenario in which a large overpressure event results in loss of containment on downstream pipeline is captured in the LRGOP model and not the Loss of Containment on Transmission Main (LOCTM) or Loss of Containment on Distribution Main or Service (LOCDM) risk models.

d. Wildfire Tranches

At the workshop, SPD Staff noted that PG&E’s Wildfire modeling consisted of 10 HFTD/HFRA Primary Distribution tranches, whereas in its Test Year 2023 GRC (A.21-06-021), there were 25 (5x5) tranches.

Staff inquired about the reasons for PG&Es changes and expressed desire to see Wildfire HFTD/HFRA tranches follow the 5x5 approach.

PG&E addresses this feedback in Exhibit (PG&E-4), Chapter 1.

e. Lack of Financial Consequences for Contractor Safety Incident Risk

SPD Staff inquired as to why there were no financial consequences for this Risk.

In response, PG&E points out that worker's compensation claims costs resulting from incidents are covered by the contractor. PG&E also does not track any residual financial costs arising from any such incidents and assumes that they are de-minimis for Risk modeling purposes. PG&E believes that overall, this is an appropriate treatment of the financial consequences of the Risk.

f. Updating Risk Values to Reflect 2023 Historical Data

SPD staff suggested that the risk analysis be updated to incorporate 2023 historical data (e.g. number of ignitions) for the Wildfire with PSPS and EPSS, Failure of Electric Distribution Overhead Assets and Loss of Containment on Gas Transmission Pipeline Risks.

PG&Es took its best efforts to incorporate the latest data in its risk analysis. However, for various reasons, this might not be feasible. First and foremost, is whether the data is available in a timely fashion for inclusion in the RAMP analysis. For all Electric Operations Risks, even though raw data for 2023 was available prior to the date RAMP will be submitted, it still requires extensive review and preparation, a process which would not be completed in time for the filing. Hence the risk analysis for Wildfire with PSPS and EPSS, and Failure of Electric Distribution Overhead Assets include historical data up to 2022. PG&E also notes that for Wildfire, the 2023 ignition data (65 reportable ignitions), while showing a decreasing trend, are still somewhat similar compared to prior years, and so PGE anticipates limited changes to the analysis if this data were incorporated.

For the Gas Operations Risks, PG&E incorporated historical data through June 2023 in its risk analysis for the reason mentioned above.

g. Inclusion of the Impacts of Wildfire Smoke

MGRA noted that with the VSL guidance provided in D.22-12-027, the Safety impact, in dollar terms, is no longer the major contributor to the Wildfire Risk value. MGRA suggested that PG&E should consider an approach similar to that adopted by San Diego Gas & Electric Company in its most recent RAMP filing (A.21-05-011).

PG&E discusses its findings related to Wildfire Smoke modeling in Exhibit (PG&E-2), Chapter 7, Environmental and Social Justice. PG&E also notes once again, that regardless of VSL, it is the policy of the state of California, the CPUC and PG&E that Safety is the top priority. This points to the need of establishing Risk Tolerance thresholds, expressed in natural units (i.e., EFs) not dollars, so that this policy can be effectively and robustly implemented. Risk Tolerance should be discussed and explored in the Risk OIR (R.20-07-013) as an avenue to further ensure that Safety is the top priority for IOUs.

h. Timeliness of Workshop

SPD staff provided feedback that PG&E's first workshop, held to satisfy Step 2B Element No. 12 of the RDF, could have been conducted one to two months earlier to give PG&E enough time to consider and act on, if appropriate, any input it receives.

PG&E recommends that this proposal should be further discussed and considered with respect to future IOU RAMP filings.

E. Final 2024 RAMP Risk Values and Comparison of Safety Risk Ranks with 2020 RAMP

Since the February pre-filing workshop where PG&E presented preliminary risk values, PG&E has finalized its Risk Values to include in the 2024 RAMP Report. While its top 40 percent Safety Risks remain the same, the individual Risk Values and relative rankings have changed. Table 4-2 shows the updated risk values.

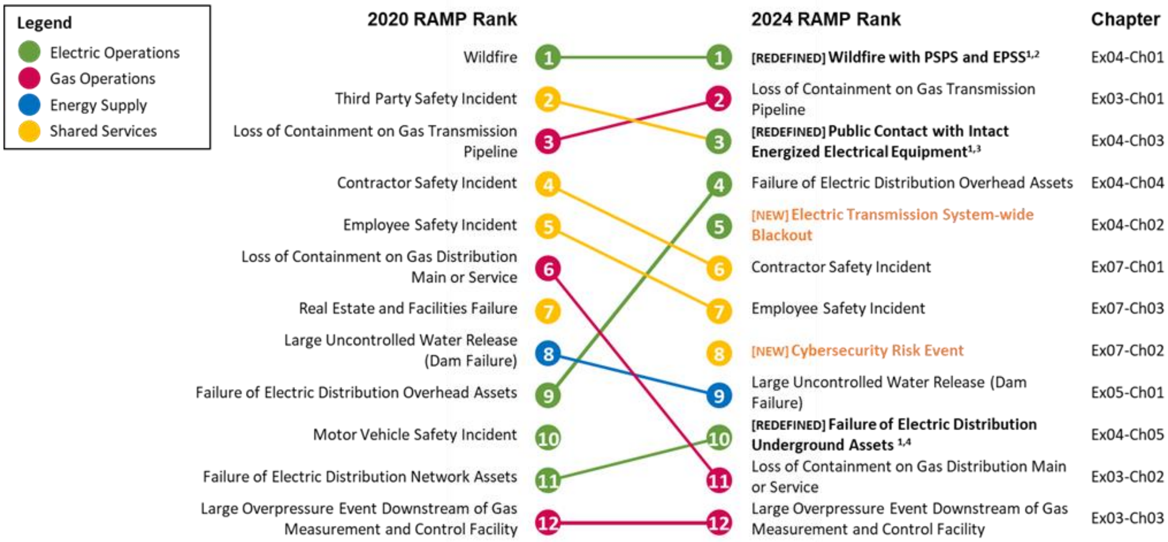
TABLE 4-2
FINAL RISK VALUES BY ATTRIBUTE IN 2024 RAMP REPORT

		TY Baseline Risk Values for 2027 ($M)				
Line No.	Risk	Safety	Electric Reliability	Gas Reliability	Financial	Total
1	Wildfire with PSPS and EPSS	222	5,466	0	1,977	7,666
2	Loss of Containment on Gas Transmission Pipeline	139	0	22	26	186
3	Public Contact with Intact Energized Electrical Equipment	60	0	0	0	60
4	Failure of Electric Distribution Overhead Assets	54	3,175	0	124	3,354
5	Electric Transmission Systemwide Blackout	52	1,844	0	8	1,903
6	Contractor Safety Incident	39	0	0	0	39
7	Employee Safety Incident	30	0	0	9	39
8	Cybersecurity Risk Event	25	915	25	42	1,007
9	Large Uncontrolled Water Release (Dam Failure)	21	0	0	237	258
10	Failure of Electric Distribution Underground Assets	19	686	0	23	728
11	Loss of Containment on Gas Distribution Main or Service	19	0	9	79	107
12	Large Overpressure Event Downstream of Gas M&C Facility	18	0	0	1	19

Note: The table is also provided in Exhibit (PG&E-2), WP RM-RMCBR-14.

As described throughout this Report, there have been several changes from the methodologies employed in the 2020 RAMP Report. These include the development and implementation of the risk assessment methodologies articulated in the RDF Phase II Decision. Figure 4-1 below identifies where 2020 RAMP risks appear in this Report as well as listing additional RAMP Risks that are newly included in the 2024 RAMP Report.

FIGURE 4-1
COMPARISON BETWEEN PG&E'S 2020 AND 2024 RAMP RISK RANKING



[1] Risk event definitions/scope have changed since the 2020 RAMP.
[2] Wildfire risk score now also reflects consequences of Public Safety Power Shutoff (PSPS) and Enhanced Powerline Safety Settings (EPSS).
[3] For Public Contact, the scope was narrowed to focus on members of the public and third-party contractors experiencing serious injuries or fatalities resulting from interactions with intact energized electric facilities, not involving asset failure.
[4] Two risk models that were previously separate, Failure of Electric Distribution Network Assets and Failure of Electric Distribution Underground Assets, have been assembled into a single model.

Several Risks exhibited minor changes in rankings, moving one or two places higher or lower, which can be attributed to a variety of factors, including updated data, modeling enhancements, and the adoption of CBA in place of MAVF. However, overall trends when comparing Risks presented in 2020 vs 2024 can be summarized as follows:

- Redefinition of Risks. Three Risks have been redefined/re-scoped since 2020. Wildfire (Exhibit (PG&E-4), Chapter 1) has been rescoped to include the impacts of PSPS and EPSS mitigations for 2024, but this did not affect its importance as PG&E's top safety risk. 2020's Third Party Safety Incident Risk has been redefined as the Public Contact with Intact Energized Electrical Equipment (Exhibit (PG&E-4), Chapter 3). The reason for this redefinition is to focus on safety incidents involving public contact with PG&E's energized electrical assets operating in normal conditions; and not to cloud the evaluation with other public interaction risks otherwise managed as part of other Risks (e.g., gas dig-ins are part of Gas Operations Loss of Containment Risks, and wire-down from third party contact is part of Failure of Electric Distribution Overhead Asset Risk). Finally, Failure of Electric Distribution Underground Assets (Exhibit (PG&E-4), Chapter 5) has been redefined to include Failure of Electric Distribution Network Assets (2020 RAMP risk) in addition to the existing Failure of Electric Distribution Underground (Radial) Assets (non-RAMP risk in 2020 RAMP Report).

- Inclusion of Electric Transmission Systemwide Blackout arising from modeling of Electric Reliability-induced Indirect Safety Consequences. In Exhibit (PG&E-2), Chapter 2, PG&E explains the reasoning and approach used to model the Indirect Safety Consequences of Electric Reliability impacts, which is new for 2024. Transmission Systemwide Blackouts lead to large-scale Reliability impacts, which in turn will have large-scale Indirect Safety Consequences, as discussed in Exhibit (PG&E-4), Chapter 2. While the top four Risks remain the same from 2020 to 2024, other Risks from 2020 were displaced at least one spot lower by the inclusion of the Electric Transmission Systemwide Blackout Risk. As a result, Real Estate and Facilities Risk is no longer part of the top 40 percent for 2024.
- Inclusion of Cybersecurity Risk Event. This is a new Risk for 2024, with a Safety ranking of eighth, which like Electric Transmission Systemwide Blackout above, is due to the inclusion of Electric Reliability-induced Indirect Safety Consequences. It is discussed in Exhibit (PG&E-7), Chapter 2.
- Failure of Electric Distribution Overhead Assets is now ranked fourth compared to ninth in 2020. The main reason for this is the inclusion of Electric Reliability-induced Safety Consequences.
- Loss of Containment on Gas Distribution Main or Service is now ranked eleventh compared to sixth in 2020. This represents a decrease of two places relative to the set of 2020 risks, as both Cybersecurity Risk Event and Electric Transmission Systemwide Blackout are new. In addition, Loss of Containment on Gas Distribution Main or Service risk has refined Seismic risk assumptions which lead to lower safety impacts while both Large Uncontrolled Water Release (Dam Failure) and Failure of Electric Distribution Underground Assets have increased safety impact.

PACIFIC GAS AND ELECTRIC COMPANY
RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 5
SAFETY CULTURE, POLICY, AND COMPENSATION

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CHAPTER 5
SAFETY CULTURE, POLICY, AND COMPENSATION

A. Introduction

Pacific Gas and Electric Company's (PG&E, or the Company, or the Utility) safety culture is a fundamental part of our operations. It includes core values and behaviors resulting from a collective commitment by leaders and individuals to emphasize safety over competing goals to ensure protection of people and the environment. This chapter provides an overview of PG&E's safety culture including leadership and executive board engagement. It also includes a discussion about PG&E's compensation policies related to safety performance.

B. PG&E's Safety Excellence Policy

Two of PG&E's stands are that everyone and everything is always safe and that catastrophic wildfires shall stop. Leadership is committed to protecting the health and safety of our coworkers, contractors, and hometowns and fostering a proactive and engaging organizational culture and safety mindset.[1] We will achieve industry-leading safety performance through the disciplined application of the PG&E Safety Excellence Management System (PSEMS)[2],[3].

1. PG&E Safety Excellence Management System

PSEMS is the systematic management of our processes, assets, and occupational health and safety to prevent injury and illness including effectively and safely controlling and governing our assets and managing the integrity of operating systems and processes. PSEMS drives continuous improvement in 4 areas: Asset Management, Occupational Health & Safety, Process Safety, and Organizational Culture & Safety Mindset. It consists of a framework of 13 elements that establish governance and operational requirements for how we operate our business to generate and deliver safe,

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1 Exhibit (PG&E-2), Workpaper (WP) RM-SAFEC-01.

2 Formerly, Health & Safety Management System (HSMS).

3 Exhibit (PG&E-2), WP RM-SAFEC-03.

reliable, affordable, and clean energy to our customers and hometowns and that all workers shall follow to keep us safe. They include:

1) Leadership Commitment and Engagement;
2) Communications and Stakeholder Engagement;
3) Risk Management;
4) Strategy, Objectives and Planning;
5) Operational Control;
6) Training and Competence;
7) Emergency Preparedness and Response;
8) Incident Reporting, Investigation and Corrective Action;
9) Contracted Services and Purchased Goods;
10) Management of Change;
11) Information, Documentation and Records Management;
12) Performance Evaluation and Improvement; and
13) Assurance.

The elements are part of a Plan-Do-Check-Act cycle to drive continual improvement across the Enterprise.

FIGURE 5-1
PSEMS MANAGEMENT SYSTEM CYCLE

A systematic, annual approach is also employed to review results, establish objectives, assess gaps, prioritize, and plan gap closure plans, and execute and monitor such plans.

More information about PSEMS can be found in PG&E's Safety Excellence Management System Manual.[4]

C. Safety Culture

PG&E's Safety Culture is described in the PG&E Organizational Culture and Safety Mindset Standard, SAFE-5005S,[5] which establishes the attributes of a Safety Conscious Work Environment (SCWE) and the 10 traits of a Healthy Safety Culture as the framework for safety culture at PG&E.

1. Safety Conscious Work Environment

The attributes of PG&E's SCWE include:

- A management attitude that promotes employee involvement and confidence in raising and resolving concerns;
- A clearly communicated Safety Excellence Policy (see Section B, PG&E's Safety Excellence Policy above) stating that safety has the utmost importance, overriding, if necessary, the demands of production and project schedules;
- A strong, independent assurance program;
- A training program that encourages a positive attitude toward safety;
- A safety ethic at all levels that is characterized by:
  - An inherently questioning attitude;
  - Attention to detail;
  - Prevention of complacency;
  - A commitment to excellence; and
  - Personal accountability in safety matters.

2. The 10 Traits of a Healthy Safety Culture

PG&E strives to embrace and embed the following Traits throughout all aspects of the Company and work being done:

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4 Exhibit (PG&E-2), WP RM-SAFEC-03.

5 See Exhibit (PG&E-2), WP RM-SAFEC-02.

1) Personal Accountability:
   - All individuals take personal responsibility for safety;
   - Responsibility and authority for safety are well defined and clearly understood; and
   - Reporting relationships, positional authority, and team responsibilities emphasize the overriding importance of safety.
2) Questioning Attitude:
   - Individuals avoid complacency and continuously challenge existing conditions and activities in order to identify discrepancies that might result in error or inappropriate action; and
   - All coworkers are watchful for assumptions, values, conditions, or activities that can have an undesirable effect on safety.
3) Effective Safety Communication:
   - Communications maintain a focus on safety;
   - Safety Communication is broad and includes:
     - Enterprise-level communication;
     - Functional Area/Division communication;
     - Job-related communication;
     - Worker-level communication;
     - Equipment labeling;
     - Operating experience;
     - Documentation;
   - Leaders use formal and informal communication to convey the importance of safety; and
   - The flow of information up the organization is seen as important as the flow of information down the organization.
4) Leadership Safety Values and Actions:
   - Leaders demonstrate a commitment to safety in their decisions and behaviors;
   - Executive and senior managers are the leading advocates of safety and demonstrate their commitment both in word and action;
   - The safety message is communicated frequently and consistently, occasionally as a stand-alone theme;
   - Leaders throughout the enterprise set an example for safety;

- Corporate policies, standards and procedures emphasize the overriding importance of safety.

5) Decision-Making:
   - Decisions that support or affect the enterprise are systematic, rigorous, and thorough;
   - Coworkers are vested with the authority and understand the expectation, when faced with unexpected or uncertain conditions, to restore the assets, equipment, and systems to a safe condition; and
   - Senior leaders support and reinforce conservative decisions.

6) Respectful Work Environment:
   - Trust and respect permeate the organization;
   - A high level of trust is established in the organization, fostered, in part, through timely and accurate communication;
   - Differing professional opinions are encouraged, discussed, and resolved in a timely manner; and
   - Coworkers are informed of steps taken in response to their concerns.

7) Continuous Learning:
   - Opportunities to learn about ways to ensure safety are sought out and implemented;
   - Experience is highly valued, and the capacity to learn from experience is well developed;
   - Training, self-assessments, and benchmarking are used to stimulate learning and improve performance;
   - Safety is kept under constant scrutiny through a variety of monitoring techniques, some of which provide an independent “fresh look.”

8) Problem Identification and Resolution:
   - Issues potentially impacting safety are promptly identified, fully evaluated, and promptly addressed and corrected commensurate with their significance; and
   - Identification and resolution of a broad spectrum of problems, including organizational issues, are used to strengthen safety and improve performance.

9) Environment for Raising Concerns:

- A SCWE is maintained where personnel feel free to raise safety concerns without fear of retaliation, intimidation, harassment, or discrimination; and
- The enterprise creates, maintains, and evaluates policies, standards and procedures that allow coworkers to freely raise concerns.

10) Work Processes:

- The process of planning and controlling work activities is implemented so that safety is maintained;
- Work management is a deliberate process in which work is identified, selected, planned, scheduled, executed, closed, and critiqued; and
- The entire enterprise is involved in and fully supports the process.

D. PG&E's Safety Leadership

PG&E's Safety Leadership consists of:

- The Chief Executive Officer (CEO), whose safety responsibilities include creating an environment where people are encouraged to raise concerns and where leaders are expected to respond to them, ensuring the adoption, and owning the leadership and engagement element of PSEMS.
- The Chief Safety Officer (CSO)/Executive Vice President (EVP). In December 2022, Dr. Matt Hayes was named as Vice President (VP) of PG&E's Enterprise Health and Safety (EHS) organization and CSO. Dr. Hayes previously served as Senior Director of Organizational Effectiveness and Training at PG&E's Diablo Canyon Power Plant (DCPP or Diablo Canyon) with more than 20 years of Generation experience. At DCPP, he was responsible for Training, Performance Improvement, the Corrective Action Program (CAP), Document Services, and Organizational Effectiveness for Generation (including safety and safety culture monitoring/assessment), and the oversight of Diablo Canyon Security and Emergency Services. As the VP of EHS and CSO, Dr. Hayes is accountable for oversight of the workforce safety strategy, including, but not limited to the Enterprise Corrective Action Program, Serious Incident and Fatality Prevention, our Company's safety standards, implementing PSEMS, developing programs for Contractor Safety and Occupational Safety &

Health, which are discussed in detail in the Employee Safety Incident[6] and Contractor Safety Incident[7] risk chapters, as well as employee technical training. The VP of EHS and CSO reports to the Operations EVP and Chief Operating Officer who reports directly to the CEO.

- Five Regional Safety Directors who are accountable for partnering with regional leadership on identifying region-specific hazards and assessing risk, verifying critical field controls, coaching on positive safety interactions, and coordinating the implementation of enterprise-wide workforce safety strategy programs within their region.

E. Governance Framework: Board of Directors

PG&E's Board of Directors has made the Safety and Nuclear Oversight Committee (SNO Committee) responsible for safety oversight at PG&E. The SNO Committee is responsible for overseeing and reviewing policies, practices, standards, goals, issues, risk, and compliance relating to safety. Among other things, the SNO Committee reviews and discusses:

- Enterprise risks and cross-cutting factors,[8] the actions management is taking to understand these risks and cross-cutting factors, and how management assesses the effectiveness of the various processes and controls to reduce exposure to these risks;
- The Utility's goals, programs, policies, and practices with respect to improving safety practices and operational performance, as well as promoting a strong safety culture; and
- Periodically visiting the Utility's nuclear and other operating facilities.

The Board holds regularly-scheduled meetings, and the SNO Committee must meet at least six times per year. Members of PG&E management regularly attend Board and Committee meetings. The SNO Committee's charters specifically require regular review, with the CSO, of the Company's long-term safety goals and objectives, as well as current staffing and budgeting needs.

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6 Exhibit (PG&E-7), Chapter 3.

7 Exhibit (PG&E-7), Chapter 1.

8 Cross-cutting factors impact either the likelihood or consequence of other risk events on PG&E's Corporate Risk Register.

F. Compensation Policies Related to Safety

PG&E's compensation policies reflect our mission to provide safe, reliable, affordable, and clean energy for our customers by promoting positive outcomes in line with those objectives. This section describes PG&E's compensation structure and how safety metrics are established, evaluated, and incorporated into employees' compensation.

1. Foundational Compensation

PG&E's employee compensation consists of two broad categories: foundational and at-risk compensation. Foundational compensation includes an employee's base pay, benefits, and pension. This portion of compensation provides a stable income as well as health, wellness, and retirement benefits. The proportion of foundational compensation in an employee's total compensation depends on the level of an employee, ranging from 100 percent for the majority of PG&E's represented employees to an average of approximately 40 percent for PG&E officers. Benefit programs are a key component of foundational compensation. These benefits promote health maintenance and disease prevention and are essential to the Company's ability to keep a diverse, skilled, experienced, and dedicated workforce that is healthy and focused on delivering safe and reliable service to customers.

2. At-Risk Compensation

At-risk compensation, or incentive compensation, is designed to be conditioned on one or more aspects of the employee's and Company's level of performance against set goals-. There are two main at-risk components of compensation—the Short-Term Incentive Plan (STIP) and the Long-Term Incentive Plan (LTIP). The current STIP and LTIP were developed as part of a rigorous reevaluation of existing incentive compensation plans and consist of objectively measurable, primarily outcome based, risk reduction measures that promote customer and workforce welfare (especially public and employee safety) and financial stability.

a. Short-Term Incentive Plan

Salaried employees, those hourly employees who are not represented by a labor agreement, and salaried employees represented by the International Brotherhood of Electrical Workers and the Engineers and Scientists of California participate in PG&E's STIP, which is PG&E's variable pay program tied to annual Company performance. The participation rates vary by employee level, from 6 percent for support level employees to 30 percent for Senior-Director level employees.[9]

STIP metrics are established each calendar year by the Compensation Committee of the PG&E Corporation Board of Directors. In 2024, 70 percent of the STIP performance metrics are focused on customer and workforce welfare (public and employee safety) and the remaining 30 percent on financial stability. The 2024 STIP's metrics are outcome based as opposed to activity or effort based. The metrics selected for the STIP are informed by the Enterprise and Operational Risk Management Program at PG&E, and the Safety Model Assessment Proceeding and Risk Assessment and Mitigation Phase proceedings before the California Public Utilities Commission (Commission).

STIP payouts are affected by the Company's performance against the established metrics. The STIP score can range from 0 percent to 200 percent of target each year. Each employee receives an individual modifier each year that can result in an adjustment of the payout, depending on how the individual performs relative to his or her individual job performance goals. Before the STIP score is finalized, the Compensation Committee reviews and approves the results, and has discretion to reduce the score (including to zero) if it believes it appropriate to do so under the totality of the circumstances.[10] Further, per the Commission's decision in Decision 20-05-053, there is a presumption that a material portion of the Utility executives' compensation shall be withheld if PG&E is the ignition source of a

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9 STIP participation level, for Officers, is approved annually by the Compensation Committee or Board of Directors.

10 The Compensation Committee and the Board exercised their discretion to reduce 2018 STIP payouts to zero in light of the devastating 2018 Camp Fire, the hardships incurred by communities, and PG&E's financial circumstances, including the need to seek relief under Chapter 11.

catastrophic wildfire, unless the Commission determines that such withholding would be inappropriate.

b. Long-Term Incentive Plan

Director-level and above positions are eligible for PG&E's LTIP, which is PG&E's variable pay program tied to long-term Company performance. The target values vary by employee level, increasing by level within the Company.

The 2024 LTIP awards, to the extent payable, consists of performance shares and/or a combination of performance and restricted stock units. LTIP awards will be calculated based on performance in three areas, Safety, Customer Experience, and Financial Stability, with objective performance metrics for a three year- performance period: (1) Safety, with two components, System Hardening Effectiveness, and Electric Corrective Maintenance in High Fire Risk Areas (promoting reduction in wildfire risk); (2) Customer Experience, System Average Interruption Duration Index (which promotes customer welfare); and (3) Financial Stability. LTIP score can range from 0 percent to 200 percent of target.

Before the LTIP score is finalized, the Compensation Committee and the independent members of the Utility Board, as applicable, review and approve the results, and have discretion to reduce or eliminate LTIP awards for any reason—subject to certain legal restrictions—with respect to any particular employee or more broadly.[11] Additionally, as noted, there is a presumption that a material portion of the Utility executives' compensation shall be withheld if PG&E is the ignition source of a catastrophic wildfire, unless the Commission determines that such withholding would be inappropriate.

PG&E recognizes and remains committed to improving safety culture and safety performance. The focus is building an accountable, transparent organization that embraces raising issues and ideas, and acts upon resolving them. PG&E is focused on working efficiently,

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[11] The Compensation Committee has this discretion for LTIP participants, other than the CEO of the Utility, for whom the independent members of the Utility Board have sole discretion.

without risking the safety of our customers, our workforce, or the community.

PACIFIC GAS AND ELECTRIC COMPANY
RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 6
CLIMATE RESILIENCE

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CLIMATE RESILIENCE

A. Introduction

As climate change continues to increase and its impacts to utility assets, operations and services grow, an expanded risk framework is needed to ensure the complex interaction of worsening climate conditions is accounted for in utility risk planning processes. Through the incorporation of targeted climate change projection data in Pacific Gas and Electric Company's (PG&E or the Company) risk modeling efforts, the Company is enhancing the climate resilience of its assets and building a more resilient and safe energy system for our customers.

PG&E believes that a comprehensive climate adaptation strategy that includes risk assessment activities and other aspects of utility investment and planning activities will increase in importance each year as the climate warms and its impacts are increasingly felt by all Californians. This is an end goal that PG&E is working toward, as detailed in part in the Company's Climate Strategy Report.[1]

This chapter provides an overview of the Company's Climate Adaptation Vulnerability Assessment (CAVA) report approach, methodology and key findings. These CAVA findings have been included in relevant risk chapters to highlight the Company's continued efforts to more fully integrate future climate change impacts in the Company's risk assessment process. This section provides information on how PG&E developed the climate risk rankings and adaptive capacity findings and includes a summary of potential climate adaptation investment options that PG&E identified when it conducted the CAVA.

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1 PG&E Climate Strategy Report (June 2022), available at: <https://www.pge.com/content/dam/pge/docs/about/pge-systems/PGE-Climate-Strategy-Report.pdf>(accessed May 3, 2024).

B. PG&E's CAVA

1. Background of CAVA

PG&E began analysis for its first CAVA in 2021 and the full document will be filed concurrently with the Company's 2024 Risk Assessment and Mitigation Phase (RAMP) filing in May 2024, consistent with Decision (D.) 20-08-049. PG&E views CAVAs as serving two purposes: (i) informing the Commission and the public about future utility climate risks and (ii) informing internal utility experts in their work to make their utilities more climate resilient.[2] The methodology PG&E applied to conduct its 2024 CAVA was consistent with requirements laid out in D.20-08-046 and facilitated identification of climate risk to various climate hazards across the Company's assets, operations, and services.

The purpose of this section is to highlight the key findings from PG&E's 2024 CAVA for asset categories that are directly related to the Risk Events included in the Company's 2024 RAMP filing. Furthermore, PG&E is attempting to integrate the findings from the CAVA across the Company's risk assessment efforts in a manner that will allow for future funding requests to reflect the findings from the 2024 CAVA. This principally consists of identifying moderate and high-risk asset categories to the climate hazards included in the assessment and identifying potential climate adaptation options that may be considered as part of the Test Year 2027 General Rate Case (GRC). Please refer to the CAVA itself for the full description and discussion of process and results.[3]

2. Approach and Methodology

PG&E considered the following decadal time frames – 2030, 2050, and 2080. Per guidance from D.20-08-046, PG&E focused its results on the 2050 time period.

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2 See D.20-08-049, p. 113, Conclusion of Law (COL) 33 ("The IOU's vulnerability assessments will provide the information the Commission and stakeholders need to determine whether infrastructure, operations, or service changes will be needed as a means of climate adaptation").

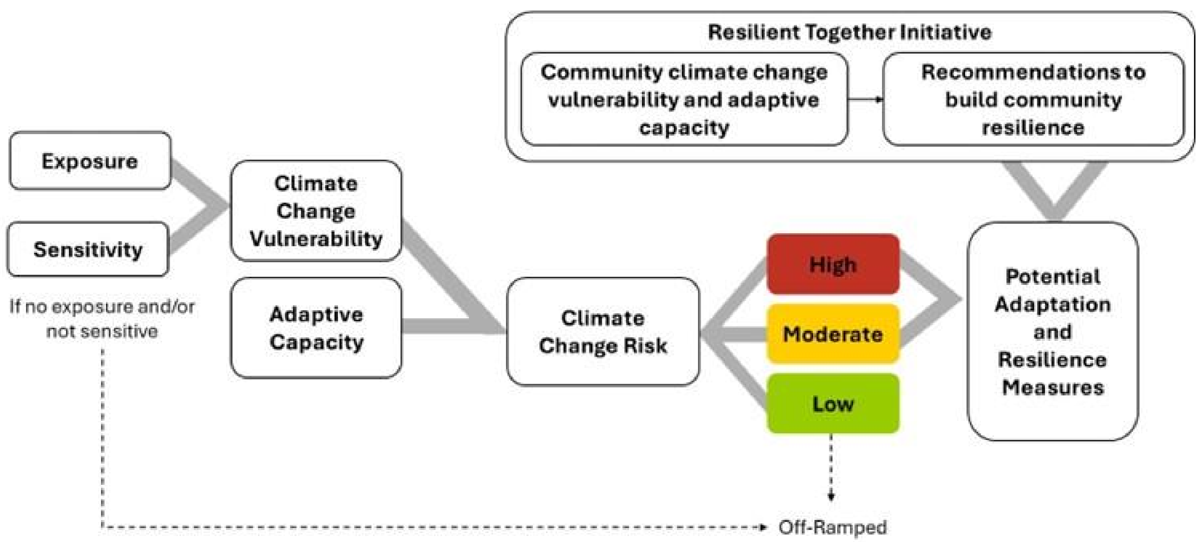
3 Concurrently with this RAMP filing, the CAVA is being provided to the associated service lists for PG&E's RAMP application.

PG&E's 2024 CAVA developed climate risks for each asset family for the following climate hazard categories: Extreme Heat, Sea Level Rise, Flooding/Precipitation, Wildfire, and Drought-Driven Subsidence.

PG&E's framework for assessing climate change risk is aligned with the methodology provided in the Climate Adaption OIR and is based on the following components:

- **Exposure**: The nature and degree of the projected climate change hazard in relation to location or operational footprint of the asset.
- **Sensitivity**: The nature of the potential effects of climate-related hazards on an asset, under conditions of exposure.
- **Vulnerability**: If an asset is exposed and is sensitive to a climate hazard, whether it is vulnerable and there is potential for detrimental impacts.

FIGURE 6-1
CLIMATE ADAPTATION VULNERABILITY ASSESSMENT FRAMEWORK FOR ASSESSING VULNERABILITY AND RISK



These factors are used to determine the relevant climate risk finding for each asset category and climate hazard condition. To determine the climate risk ranking, we assessed the vulnerability of the asset category to each climate hazard in combination with a review of the current adaptive capacity. The table below details the three adaptive capacity rankings used in this assessment. The primary adaptive capacity rankings were made with a focus on the expected climate hazard conditions associated with the 2050 time period. The adaptive capacity rankings for the asset families are shown throughout the RAMP report. These adaptive capacity rankings were created and assessed through a separate process from the RAMP and are reflective of known and in-place mitigations and controls at the time of the CAVA assessment and do not include any new or expanded mitigations and controls developed as part of the 2024 RAMP.

3. Climate Risk Categories and Definitions

Adaptive capacity is the ability of an asset or system to moderate or eliminate identified vulnerability and impacts; this can also be understood as an "ability to cope." This includes any aspect of design, planning, operations, monitoring, emergency response capacities, and other PG&E capabilities. Table 6-1 shows the definitions of the three levels of PG&E's adaptive capacity ranking: Low, Moderate, and High.

TABLE 6-1
PG&E'S ADAPTIVE CAPACITY DEFINITIONS

Line No.	Ranking	Adaptive Capacity Definition
1	Low	PG&E has no current capabilities to address the climate hazard.
2	Moderate	PG&E has some capabilities, but these might not address the climate hazard sufficiently to reduce potential impacts given vulnerabilities identified or may not address climate hazard before vulnerability is realized.
3	High	PG&E's current capabilities account for the climate hazard sufficiently and reduce potential impacts given vulnerabilities identified.

PG&E used a qualitative approach to climate risk findings based on considerations of exposure, sensitivity, and adaptive capacity. Table 6-2 shows the definitions of the three levels of climate risk ranking, Low, Moderate, and High.

TABLE 6-2
PG&E'S CLIMATE RISK DEFINITIONS

Line No.	Ranking	Climate Risk Definition
1	Low[(a)]	Not projected to be a climate change issue.
2	Moderate	Vulnerable assets, opportunities exist to bolster current operational/planning processes to enable greater resiliency. Recommend addressing issue.
3	High	Vulnerable assets, current operational/planning processes likely not sufficient given future projections. High priority climate change issue.

(a) Low rated asset categories are considered to be off-ramped, consistent with D.20-08-046. Off-ramped assets and climate hazards are then not considered for further analysis. This determination will be reviewed during the Company's next CAVA.

The quantification of climate hazards to an event-based risk model is very complex and time consuming. Given this complexity, PG&E has used the results the Company's 2024 CAVA to help prioritize what climate hazard impacts to directly consider across the Risk Events included in the 2024 RAMP.

4. Key Findings

Impacts of climate change are here and changes in environmental conditions and extreme weather are projected to continue creating a more challenging environment for PG&E's operations. These conditions present direct and indirect risks to PG&E's assets and operations making day-to-day system operation and planning more difficult. These impacts include:

- Average and extreme temperatures are projected to increase over time. More extreme heat waves pose both direct and indirect risks especially to electric assets. Coastal areas will remain cooler than inland areas, but temperatures in both zones will rise.
- Coastal flooding is projected to worsen as sea levels continue to rise, potentially threatening assets that are within future inundation ranges. In particular, areas along the San Francisco Bay and the San Joaquin Delta will see more widespread and severe flooding especially during storm events. Sea level rise is projected to increase 1-3 feet by 2050.

- More frequent and intense storms, rain, and resulting flooding pose a risk to electric, gas and generation equipment that are located on or near waterways, flood plains, and landslide prone areas.
- Coastal storm surge coupled with rising sea levels is likely to exceed flooding thresholds or overtop flood barriers, resulting in direct damage to assets and operations, increased maintenance, and/or increased emergency response before and after an event.
- Non-hardened or protected electric equipment is highly sensitive to impacts of wildfire. Underground electric and gas assets can be undermined by disrupted soil conditions.
- The interactions of various climate-driven events may lead to cascading or compounding impacts in which a hazard is exacerbated or multiplied by other hazards, for example rain-driven landslides and drought-driven subsidence.

Table 6-3 summarizes the climate risk rankings for each climate hazard assessed in the CAVA and the Company's corresponding assets, operations, and services.

TABLE 6-3
CLIMATE ADAPTATION VULNERABILITY ASSESSMENT CLIMATE RISK RANKING

Line No.	Functional Area	Asset Families	High Heat	Heavy Rain /Flooding	Sea Level Rise	Wildfire
1	Electric	Transmission	Moderate	Moderate	Moderate	High
2	Electric	Substation	Moderate	Moderate	Moderate	Moderate
3	Electric	Distribution	High	Moderate	Moderate	High
4	Gas	Compression & Processing, Storage	Low	High	High	Moderate
5	Gas	Measurement and Control	Low	Moderate	Low	Low
6	Gas	Transmission Pipeline	Low	Moderate	Low	Low
7	Gas	Distribution Pipeline	Low	Moderate	Low	Moderate
8	Gas	LNG/CNG	Low	Low	Low	Low
9	Generation	Hydroelectric	Low	High (non-dam assets) Moderate (FERC high and significant hazard dams)	Not Applicable	High
10	Generation	Natural Gas	Low	Low	Low	Low
11	Generation	Solar	Low	Low	Low	Low
12	Generation	Nuclear	Low	Low	Low	Low
13	Facilities	Offices, yards, aviation, etc.	Low	Low	Low	Low
14	IT Assets	Data centers, fiber optic cable, etc.	Low	Low	Low	Low

C. Climate Adaptation Vulnerability Assessment Adaptation Options

PG&E's CAVA focuses on asset-level vulnerabilities and existing adaptive capacity to future climate hazard conditions to evaluate the need for incremental climate adaptation options. D.20-08-046 states,

> The vulnerability assessments should identify any challenges the IOUs will face due to climate change and describe possible solutions ranging from <u>easy to difficult</u>. The specific projects and climate change mitigations themselves will be chosen in the GRC or other proceeding seeking project funding.[4]

PG&E's CAVA provides potential climate adaptation options to address specific climate hazards that were ranked as moderate or high. The adaptation options identified in the CAVA are not ranked from easy to difficult. Two key factors limit the ability to readily determine the ease of any potential adaptation

4 D.20-08-046, p. 117, COL 56 (emphasis added).

options: (1) The lack of a clear definition of “easy” or “difficult” adaption options, and (2) uncertainty around the feasibility and level of effort for implementation of any adaptation options identified in the CAVA, without each option being individually considered in the Company’s risk and investment planning processes.

Table 6-4 below summarizes the adaptation options PG&E identified in the CAVA for moderate and high climate hazards.[5] These options include changes to internal PG&E risk management practices, asset hardening, changes to operational standards and practices, and the further consideration of climate change impacts in the Company’s planning and investment processes.

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[5] See PG&E’s Climate Adaptation Vulnerability Assessment (available May 15, 2024), Section 4 Adaptation and Resilience: Potential Measures and Next Steps for a more detailed accounting of potential CAVA Adaptation Options.

TABLE 6-4
CLIMATE ADAPTATION VULNERABILITY ASSESSMENT ADPATION OPTIONS

Line No.	Climate Hazard	Asset Family	CAVA Adaptation Options
1	Extreme Heat	Electric Transmission	1. Update temperature assumptions in maximum conductor loading calculations 2. Plan for climate-informed capacity projects 3. Implement real-time temperature conductor monitoring 4. Implement demand response and non-wires solutions
2	Extreme Heat	Electric Distribution	1. Incorporate forward-looking climate projections into load forecasts 2. Accelerate asset lifecycle replacement 3. Move vulnerable lines underground 4. Plan for climate-informed capacity projects 5. Implement demand response and non-wires solutions 6. Update line ratings 7. Reduce wind speed ratings 8. Transformer temperature sensors
3	Extreme Heat	Electric Substation	1. Provide additional cooling 2. Adopt updated design standards 3. Implement demand response and non-wires solutions 4. Plan for climate-informed capacity projects 5. Increase the safety margin in transformer loading 6. Provide additional monitoring 7. Increase the availability of mobile transformer and CEM units
4	Heavy Rain/ Flooding	Electric Transmission	1. Ensure climate-informed siting and design of new construction 2. Harden vulnerable structures 3. Develop emergency response plans
5	Heavy Rain/ Flooding	Electric Distribution	1. Further elevation of pad-mounted equipment 2. Accelerate/target replacement of live-front transformers with dead-front/submersible designs for pad-mount transformers 3. Increase targeted sectionalization
6	Heavy Rain/ Flooding	Electric Substation	1. Increase measures to prevent flooding 2. Improve drainage and pumping capacity 3. Install or improve pumping capacity 4. Elevate critical equipment 5. Implement waterproofing 6. Relocate vulnerable facilities 7. Temporary (deployable) flood barriers 8. Evaluation of regional collaboration partnerships
7	Heavy Rain/ Flooding	Natural Gas Compression & Processing, Storage	1. Incorporate low-probability flood events
8	Heavy Rain/ Flooding	Natural Gas Transmission Pipeline	1. System hardening

TABLE 6-4
CLIMATE ADAPTATION VULNERABILITY ASSESSMENT ADPATION OPTIONS
(CONTINUED)

Line No.	Climate Hazard	Asset Family	CAVA Adaptation Options
9	Heavy Rain/ Flooding	Natural Gas Distribution Pipeline	1. Pipeline design measures to decrease risk of damage from ground displacement 2. Increased corrosion protection 3. Monitoring for landslide risk
10	Heavy Rain/ Flooding	Natural Gas Measurement & Control	1. Prioritized physical protection measures at stations in flood-prone areas 2. Relocate stations in flood-prone areas 3. Review vent heights for low-pressure stations located in floodplains 4. Continue to invest in system monitoring
11	Heavy Rain/ Flooding	Generation: Hydroelectric	1. Develop preliminary risk rating and identify vulnerable assets 2. System hardening 3. Enhanced hydrologic forecasting and monitoring 4. Enhanced monitoring of asset conditions
12	Sea Level Rise	Electric Transmission	1. Ensure climate-informed siting and design of new construction 2. Apply corrosion-resistant coatings 3. Harden vulnerable structures 4. Develop emergency response plans
13	Sea Level Rise	Electric Distribution	Refer to flooding and precipitation section for potential adaptation options.
14	Sea Level Rise	Electric Substation	Refer to flooding and precipitation section for potential adaptation options.
15	Sea Level Rise	Natural Gas Compression & Processing, Storage	Refer to flooding and precipitation section for potential adaptation options. 1. Incorporate sea level rise projections
16	Wildfire	Electric Transmission	No climate adaptation options are presented in the CAVA.
17	Wildfire	Electric Distribution	No climate adaptation options are presented in the CAVA.
18	Wildfire	Electric Substation	No climate adaptation options are presented in the CAVA.
19	Wildfire	Natural Gas Compression & Processing, Storage	No climate adaptation options are presented in the CAVA.
20	Wildfire	Natural Gas Measurement & Control	No climate adaptation options are presented in the CAVA.
21	Wildfire	Natural Gas Distribution Pipeline	1. Reducing the size of gas shutdown zones
22	Wildfire	Generation: Hydroelectric	1. Debris catchment basins and water conveyance carry-overs 2. Debris booms 3. Asset restoration

D. Lessons Learned

The 2024 CAVA, which will be filed concurrently with this report, is PG&E's first effort to holistically evaluate how climate change will qualitatively impact the Company's assets, operations, and services. This evaluation did not include a direct assessment of how changes in climate hazards will impact the Company's Enterprise Risks directly. Instead, the evaluation was focused on the exposure, sensitivity, vulnerability, and adaptive capacity of families of asset categories and specific operations and services. This difference in scope between the CAVA and RAMP has limited the ability to fully integrate the impacts of climate change within this report.

In its 2022 RAMP report, Southern California Edison Company (SCE) suggested that the commission "consider placing some separation between the filing date of the CAVA and the filing date of the RAMP, rather than having both filings submitted on the same date."[6] PG&E supports this and believes that the filing of the CAVA one year prior to the RAMP report would allow further integration of these results and climate adaptation options within each utility's planned mitigation and control program. (Integration of CAVA results into this filing were a challenge since CAVA results were still being finalized as this report was developed).

There is an ongoing need to align operational risk assessment as performed in RAMP and long-term climate risk assessment as performed in CAVA. PG&E believes that it will be important to further clarify and potentially align the RAMP and CAVA assessments so that investments responsive to projected climate hazards can become a standard element of risk and investment proceeding.

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6 A.22-05-013, SCE 2022 RAMP Report, Appendix B, Climate Change, p. 11.

PACIFIC GAS AND ELECTRIC COMPANY
RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 7
PG&E'S ENVIRONMENTAL AND SOCIAL JUSTICE PILOT STUDY IMPLEMENTATION

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PG&E'S ENVIRONMENTAL AND SOCIAL JUSTICE PILOT STUDY IMPLEMENTATION

A. Introduction

In compliance with the Phase II Decision (D.) 22-12-027 of the Risk-Based Decision-Making Framework (RDF) Order Instituting Rulemaking (OIR, R.20-07-013), Pacific Gas and Electric Company (PG&E or the Company) hereby submits the first Environmental and Social Justice (ESJ) Pilot Study.

PG&E supports the California Public Utility Commission's (CPUC, or Commission) desire to identify and address potential equity issues that may arise in the identification and mitigation of risks as directed in D.22-12-027 and identifies this Pilot Study to be a key action item to implementing PG&E's ESJ Policy:[1]

> At PG&E, Environmental and Social Justice means making better business decisions by understanding the impacts of our activities and investments on environmental and social justice communities, while providing more sustainable, inclusive, and equitable customer solutions. Environmental and social justice communities consist of disadvantaged communities, low-income communities, and historically marginalized racial and ethnic communities who have been disproportionately impacted by environmental hazards. To better serve environmental and social justice communities, we will:
>
> - Take responsibility for our actions and operations – past, present, and future.
> - Comply fully with the letter and spirit of all applicable environmental and social justice laws and regulations.
> - Actively seek community input and use data-driven tools to better understand potential cumulative impacts of PG&E business decisions and to prioritize our actions to help support sustainable communities.

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[1] PG&E Environmental and Social Justice Policy, available at: <https://www.pgecorp.com/assets/pgecorp/localized/en/sustainability/corporate-responsibility-sustainability/reports/2023/prosperity/energy-affordability-equity/pge_ej_policy.pdf> (accessed May 6, 2024).

- Incorporate environmental and social justice considerations into our operations and energy delivery to maximize opportunities for small and diverse business in PG&E's supply chain.
- Consider environmental and social justice impacts in our policy engagement to create opportunities for and minimize adverse effects on environmental and social justice communities.
- Educate our coworkers about our Environmental and Social Justice Policy and how to operationalize the policy in their work practices.
- Maintain open communication and seek opportunities to partner with our stakeholders on environmental and social justice concerns.
- Strengthen relationships with the Native American tribal governments and communities we serve and develop partnerships to better address their environmental concerns.
- Conduct our business in a manner that respects the human rights of all individuals, as outlined in our Human Rights Policy.

PG&E appreciates feedback on this PSP that helps PG&E better to consider and advance equity in its risk framework.

1. Purpose

The purpose of PG&E's ESJ PSP is to address the seven action items in D.22-12-027:

Action Item #1: Consider equity in the evaluation of consequences and risk mitigation within the RDF, using the most current version of CalEnviroScreen to better understand how risks may disproportionately impact some communities more than others;

Action Item #2: Consider investments in clean energy resources in the RDF, as possible means to improve safety and reliability and mitigate risks in [Disadvantaged and Vulnerable Communities] DVCs;

Action Item #3: Consider mitigations that improve local air quality and public health in the RDF, including supporting data collection efforts associated with Assembly Bill (AB) 617 regarding community air protection program;

Action Item #4: Evaluate how the selection of proposed mitigations in the RDF may impact climate resiliency in DVCs;

Action Item #5: Evaluate if estimated impacts of wildfire smoke included in the RDF disproportionately impact DVCs;

Action Item #6: Estimate the extent to which risk mitigation investments included in the RDF impact and benefit DVCs independently and in relation to non-DVCs in the investor-owned utilities (IOU) service territory; and

Action Item #7: Enhance outreach and public participation opportunities for DVCs to meaningfully participate in risk mitigation and climate adaptation activities consistent with D.20-08-046.[2]

2. Development

In November 2020, in response to the Proposed Decision, PG&E assembled a core team to implement the ESJ PSP. The core team is led by the Enterprise and Operational Risk Management (EORM) team and comprised of PG&E's ESJ lead and representatives from Corporate Sustainability, Climate Resilience, Law, and Regulatory Relations.

3. External Feedback

PG&E presented the ESJ Pilot Study Plan PG&E's internal Community Perspectives Advisory Council (C-PAC) and invited the Community-Based Organizations Working Group (CBOWG) on June 15, 2023, presented to the CPUC-organized Disadvantaged Communities Advisory Group (DACAG) on June 16, 2023, and hosted a public webinar on July 20, 2023. In these forums PG&E presented on the ESJ Pilot Study Action Items, the Pilot Study Plan for addressing each Action Item, and solicited feedback on each proposal. PG&E made significant changes to its ESJ Pilot Study Plan based on the feedback received in these forums. PG&E provides details about the external feedback received in the discussion for Action Item #7.

4. Additional ESJ Efforts

PG&E has developed various mapping tools focused on our service area and identifying Disadvantaged Communities' (DAC) and other vulnerable communities in our service area. The mapping data has been translated into Google Earth, Geographic Information Systems software (GIS), and Palantir Foundry. These tools will allow us internally and externally to improve projects and decision-making aimed at reducing risk impacts on communities.

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[2] D.22-12-027, pp. 65-67, Ordering Paragraph (OP) 5.

The mapping tools currently contain the below layers:

- **Low-Income community (less than 80 percent State Median)** – State of CA low-income data;
- **Low-income community (less than 80 percent Area Median Income)** – Federal low-income data;
- **CARB DAC AB 617** – Communities in PG&E service area that are part of the CA Air Resources Board's AB 617 program – Community Air Protection Program Resource Center | California Air Resources Board;
- **Tribal Trust Lands PG&E** – Federal and state designated tribal lands in California;
- **DAC Top 25 percent CalEnviroScreen 4.0** – CalEnviroScreen4.0 top 25 percent. CalEnviroScreen 4.0 Results (arcgis.com);
- **U.S. Department of Energy Disadvantaged Justice40** – U.S. Department of Energy, Federal Justice40 communities. Energy Justice Dashboard (anl.gov);
- **Top 5 percent of Pollution Burden CalEnviroScreen 4.0** – Pollution burden only data of CalEnviroScreen 4.0;
- **Top 5 percent of Population Characteristics CalEnviroScreen 4.0** – Population characteristics of CalEnviroScreen 4.0;
- **U.S. Department of Transportation Justice 40 Disadvantaged Community** – ETC Explorer - National Results | USDOT Equitable Transportation Community (ETC) Explorer (arcgis.com);
- **Rural Area By Census** – United States rural areas based on the 2020 census;
- **Census Tract 2020** – 2020 census tract data;
- **Census Tract 2010** – 2010 census tract data;
- **Zip Code** – Zip code boundaries; and
- **County** – County boundaries.

B. PG&E's ESJ PSP

1. Action Item #1

Consider equity in the evaluation of Consequences and risk mitigation within the RDF, using the most current version of CalEnviroScreen to better understand how risks may disproportionately impact some communities more than others.

a. Learning Objective

Pilot a process for identifying risk impacts and equity in risk reductions in DVC.

b. Deliverable

PG&E intends to obtain available location data on risk consequences and mitigation level for the following risks:

- Loss of Containment on Gas Transmission Pipeline (LOCTM);
- Large Uncontrolled Water Release (LGUWR); and
- Wildfire (WLDFR) with Public Safety Power Shutoff (PSPS) and Enhanced Powerline Safety Settings (EPSS).

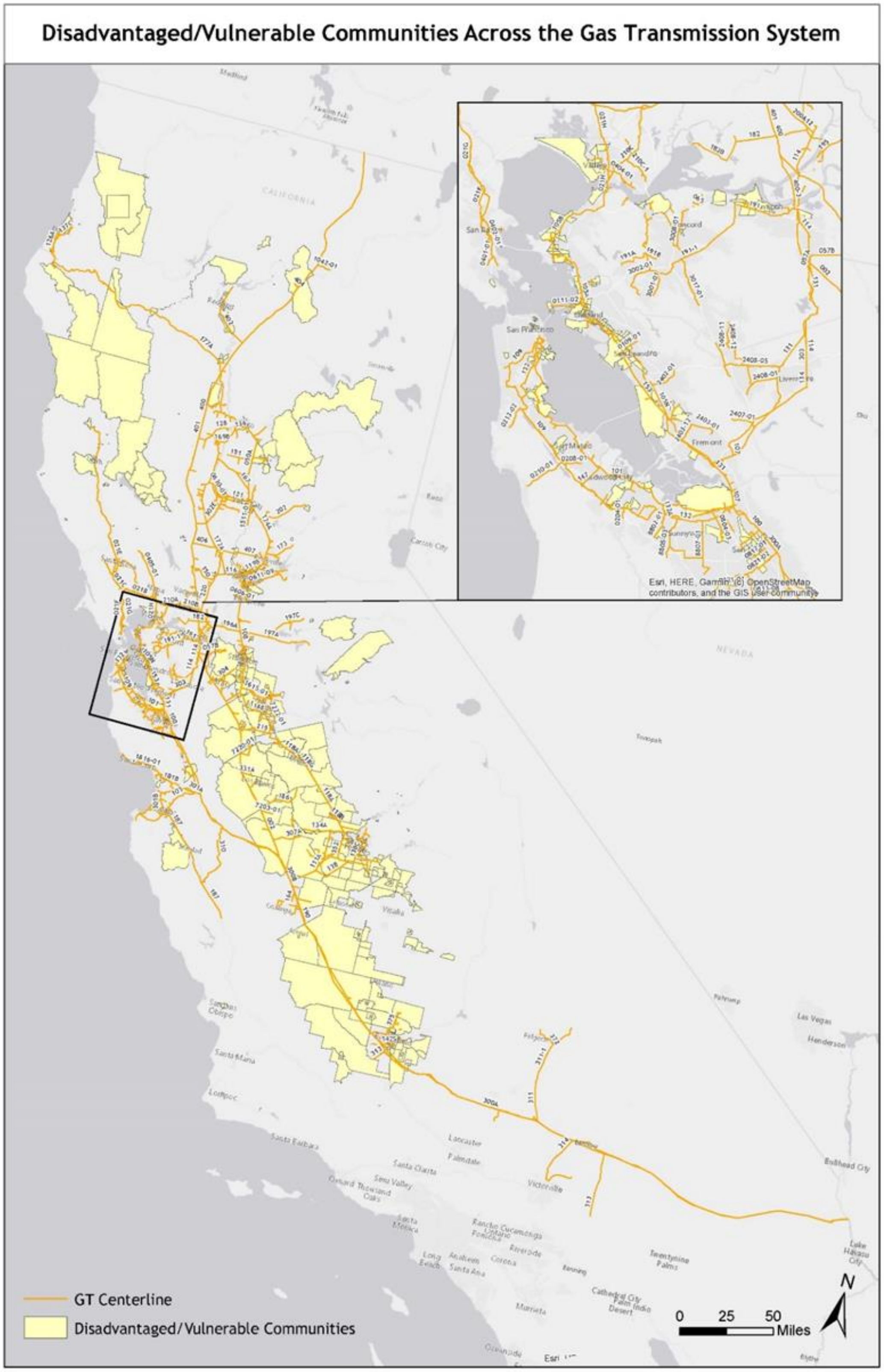
c. Discussion

1) LOCTM

As part of this PSP, DVCs, as identified in CalEnviroScreen, were mapped into the Gas Transmission System mapping tool, GIS. This enabled the analysis necessary to determine the impact to DVCs from the LOCTM risk. This also provides a lasting upgrade to PG&E's ability to determine the impact of planning and improve prioritization of projects in and around DVCs.

Approximately 1/4 of the Gas Transmission System overlaps with California's DVCs (about 1,700 miles out of about 6,500 miles), shown in Figure 7-1. It is evident that several of our Transmission Integrity Management Plan's (TIMP) Controls and Mitigations are overlapping with DVCs. Using census tracts to represent a DVC's population lends itself to a broader catchment area than the pipe's potential impact radius. Additional research would be necessary to compare DVCs and TIMP assessments to determine any disproportionate risk impact on some communities relative to others. The results of the ESJ PSP risk analysis can be found in Exhibit (PG&E-3), Chapter 1, Section B.8.a.

FIGURE 7-1
DISADVANTAGED AND VULNERABLE COMMUNITIES ACROSS THE GAS TRANSMISSION SYSTEM

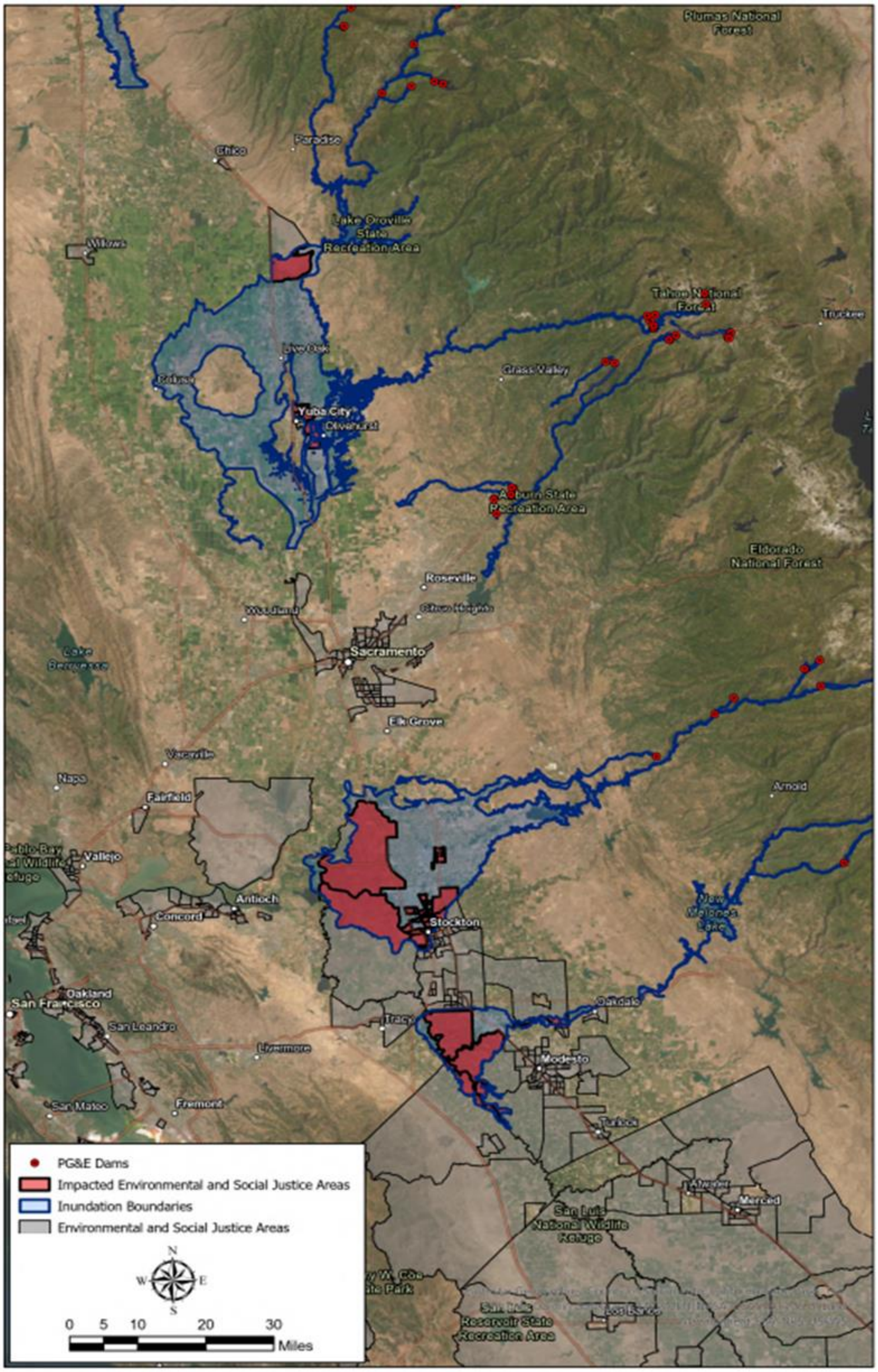


2) LGUWR

PG&E recently initiated an effort to map hydro assets into GIS; in support of the PSP, PG&E expanded this effort to include the inundation zones for each dam. As DVCs were already in GIS as part of the LOCTM effort, PG&E utilized the efficiency of the GIS mapping of DVCs to identify where the inundation zone of a dam coincided with a DVC, see figure 7-2.

PG&E has gained insights from this initiative as prior to the ESJ PSP, hydro assets, inundation zones, and DVCs were not available in a single tool. PG&E, per hydro licensing requirements, is often in contact with tribes and can also now use the better understanding of impacts of inundation on DVCs to inform its decisions.

FIGURE 7-2
DISADVANTAGED AND VULNERABLE COMMUNITIES COINCIDENT WITH DAM INUNDATION ZONES IN PG&E'S SYSTEM



PG&E also provides in Table 7-1 the complete list of dams and whether the inundation zone meets with a tribal area or DVC (note, both are considered DVCs per D.22-12-017; the separation was used for PG&E's own purposes, but both are treated equally in the PSP). Of the 60 dams included in LGUWR, 19 impact DVCs. The number of dams here differs from the number in the risk tranches because if an inundation zone overlaps with a lower hazard dam, it would be captured separately in this list but inclusively in the risk analysis of Exhibit (PG&E-5). The results of the ESJ PSP analysis for the risk can be found in Exhibit (PG&E-5), Chapter 1, Section B.3.b.

TABLE 7-1
LIST OF PG&E HIGH AND SIGNIFICANT CONSEQUENCE DAMS WITH INUNDATION ZONES COINCIDING WITH DVCS OR TRIBLE LANDS

Line No.	Group	Dam	DVCs within Inundation Zone	Tribal Lands Areas within Inundation Zone
1	01 McCloud	McCloud	No	No
2	02 Pit River	Iron Canyon	No	No
3	02 Pit River	Pit 1 Forebay	No	Yes
4	02 Pit River	Pit 3	No	Yes
5	02 Pit River	Pit 4	No	Yes
6	02 Pit River	Pit 5 Open Conduit	No	Yes
7	02 Pit River	Pit 6	No	Yes
8	02 Pit River	Pit 7	No	Yes
9	02 Pit River	Pit 7 Afterbay	No	No
10	03 Battle Creek	Macumber	No	No
11	03 Battle Creek	North Battle Creek	No	No
12	04 Eel River	Cape Horn	No	No
13	04 Eel River	Scott	No	Yes
14	05 West Branch Feather River	Philbrook	No	No
15	05 West Branch Feather River	Round Valley	No	No
16	06 Feather River	Belden	No	No
17	06 Feather River	Bucks Lake	Yes	No
18	06 Feather River	Butt Valley	No	No
19	06 Feather River	Cresta	No	No
20	06 Feather River	Grizzly Forebay	No	No
21	06 Feather River	Lake Almanor	Yes	No
22	06 Feather River	Lower Bucks	No	No
23	06 Feather River	Rock Creek	No	No

TABLE 7-1
LIST OF PG&E HIGH AND SIGNIFICANT CONSEQUENCE DAMS WITH INUNDATION ZONES COINCIDING WITH DVCS OR TRIBLE LANDS
(CONTINUED)

Line No.	Group	Dam	DVCs within Inundation Zone	Tribal Lands Areas within Inundation Zone
24	07a Yuba River	Blue Lake	No	No
25	07a Yuba River	Fordyce	Yes	No
26	07a Yuba River	Rucker	No	No
27	07a Yuba River	Spaulding No. 1	Yes	No
28	07a Yuba River	Spaulding No. 2	Yes	No
29	07a Yuba River	Spaulding No. 3	Yes	No
30	07b Yuba River	Kidd Lake	No	No
31	07b Yuba River	Kidd Lake Auxiliary	No	No
32	07b Yuba River	Peak Lake, Upper	No	No
33	08 Bear River	Drum Forebay	No	No
34	09 Coon Creek	Halsey Afterbay	No	No
35	09 Coon Creek	Halsey Forebay No. 1	No	No
36	09 Coon Creek	Halsey Forebay No. 2	No	No
37	09 Coon Creek	Rock Creek Multiple Arch	No	No
38	09 Coon Creek	Rock Creek North Wing Auxiliary	No	No
39	09 Coon Creek	Rock Creek South Wing Auxiliary	No	No
40	09 Coon Creek	Wise Forebay	No	No
41	10 North Fork American River	Lake Valley	No	No
42	10 North Fork American River	Lake Valley Auxiliary	No	No
43	11 Mokelumne	Bear, Lower	Yes	No
44	11 Mokelumne	Bear, Lower No. 2	Yes	No
45	11 Mokelumne	Bear, Upper	Yes	No
46	11 Mokelumne	Blue, Upper	No	No

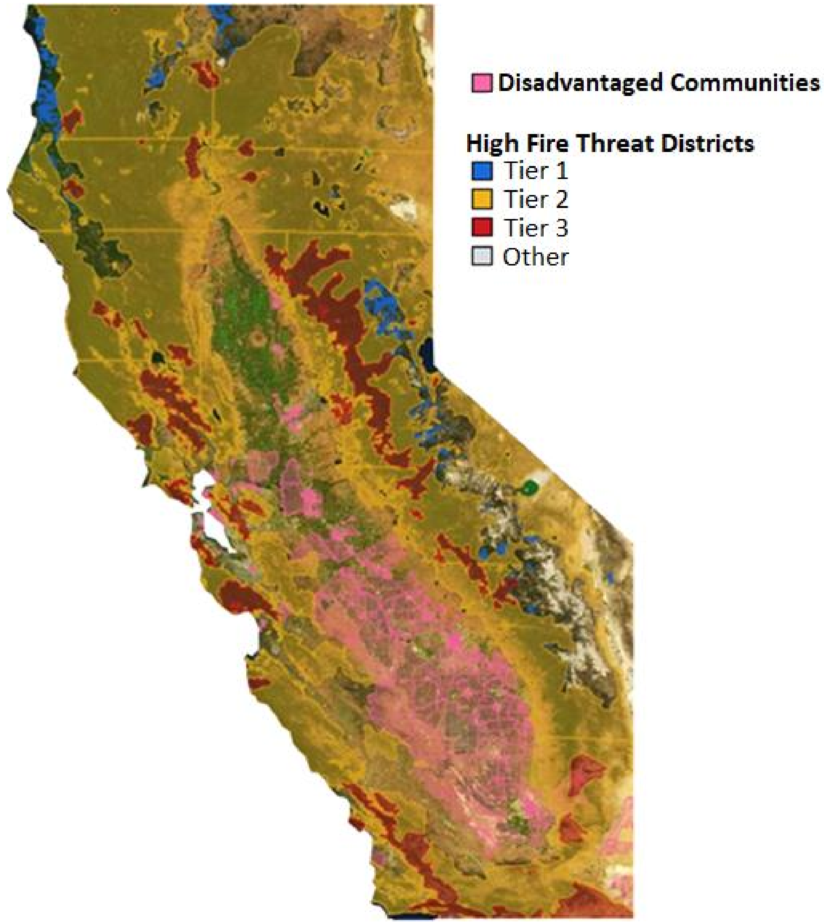
TABLE 7-1
LIST OF PG&E HIGH AND SIGNIFICANT CONSEQUENCE DAMS WITH INUNDATION ZONES COINCIDING WITH DVCS OR TRIBLE LANDS
(CONTINUED)

Line No.	Group	Dam	DVCs within Inundation Zone	Tribal Lands Areas within Inundation Zone
47	11 Mokelumne	Salt Springs	Yes	No
48	11 Mokelumne	Tabeaud	No	No
49	11 Mokelumne	Tiger Creek Afterbay	No	No
50	11 Mokelumne	Tiger Creek Regulator	No	No
51	12 Stanislaus River	Lyons	No	No
52	12 Stanislaus River	Relief	Yes	No
53	12 Stanislaus River	Strawberry	No	No
54	13 San Joaquin River	Crane Valley	No	Yes
55	13 San Joaquin River	Manzanita	No	No
56	14 Kings River	Balch Afterbay	No	No
57	14 Kings River	Balch Diversion	No	No
58	14 Kings River	Courtright	No	No
59	14 Kings River	Wishon	No	No
60	14 Kings River	Wishon Auxiliary No. 1	No	No

3) Wildfire with PSPS and EPSS

PG&E had mapped DVCs in its wildfire risk mapping tool, Foundry, in an effort prior to the PSP as a part of its internal ESJ efforts. PG&E then determined the assets, as aligned to tranches in the wildfire risk, that overlapped with DVCs. Figure 7-3 provides the DVC mapping in Foundry with additional layering of High Fire Threat Districts. The results of the ESJ PSP analysis can be found in Exhibit (PG&E-4), Chapter 1, Section B.8.d.

FIGURE 7-3
HIGH FIRE THREAT DISTRICTS AND DVC OVERLAY FROM PG&E'S FOUNDRY MAPPING



2. Action Item #2

Consider investments in clean energy resources in the RDF, as possible means to improve safety and reliability and mitigate risks in DVCs.

a. Learning Objective

Improve capabilities for identifying and enabling investments in clean energy in DVCs.

b. Deliverable

The Microgrid Incentive Program (MIP) and Community Microgrid Enablement Program (CMEP) both represent investments in clean energy resources that should improve safety and reliability and mitigate risks in DVCs.

c. Discussion

1) MIP

In conformance with CPUC Decisions in the Microgrids and Resiliency proceeding,[3] PG&E launched the first application window in 2024 for its MIP. The MIP provides up to $15 million per project for the development of clean community microgrids in DVCs, to support populations impacted by grid outages. The microgrids will provide an additional layer of energy resilience to these DVCs, and must meet certain clean energy requirements as put forth by the CPUC.[4]

In addition, D.21-01-018 provided the following MIP objectives:

- Advance microgrid technology for climate response resiliency;
- Advance system benefits of microgrids equitably to DVCs for the purpose of public health, safety, and welfare;
- Alleviate the potential that existing inequities would worsen for counties hardest hit by climate change and de-energization impacts with already vulnerable populations and too few ratepayers; and
- Inform future regulatory action to the benefit of all customers.

MIP was developed through a collaborative stakeholder engagement process that included seven stakeholder workshops, as well as meetings with environmental justice groups and other groups who advocate on behalf of disadvantaged, low-income, and vulnerable populations. PG&E, along with Southern California Edison and San Diego Gas and Electric Company jointly submitted a Proposed MIP Implementation Plan on December 3, 2021 for stakeholder comment. The CPUC issued a final decision on the implementation plan in D.23-04-034.

MIP is funded through distribution rates and PG&E's program budget allocation is $79.2 million. PG&E anticipates holding 2-3 application windows for communities seeking MIP funding. PG&E is

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3 D.21-01-018 and D.23-04-034.

4 D.23-04-034, pp. 81-82, Conclusion of Law 5.

currently in the midst of working with community applicants for the first tranche of funding under MIP, which has an application deadline of June 28, 2024. In the second half of 2024, the first round of awardees will be identified, and PG&E will begin working with them on the studies that are required to develop microgrids on PG&E's distribution system. PG&E looks forward to working with communities to provide an additional layer of energy resilience in the form of a clean community microgrid.

2) CMEP

PG&E proposed the CMEP in 2020 in Track 1 of the Microgrids and Resiliency OIR[5] in order to support those communities looking for ways to safely keep the power on during extreme weather, PSPS, and other events. The program helps communities design permanent, multi-customer microgrids by providing incremental technical and financial support on a prioritized basis for qualifying projects in areas with the greatest resilience needs. The CPUC approved the program, with modifications, in D.20-06-017 and Resolution E-5127. The program provides up to $3 million per project in cost offsets for equipment to enable the safe islanding of a microgrid, such as isolation devices, undergrounding, and equipment such as microgrid controllers.

In 2023, with the approval of MIP, PG&E modified the eligibility criteria for CMEP to align with that of MIP. In this way, CMEP now is only available to DVCs who are vulnerable to outages. The two programs work side-by-side, with CMEP providing cost offsets for equipment to enable the safe islanding of a microgrid, and MIP providing funding for the distributed energy resources (DER) and other equipment and services to enable development of a community microgrid. CMEP remains an important program, alongside the MIP, to provide energy resilience to DVCs throughout our service area, in the form of clean community microgrids.

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5 R.19-09-009.

3. Action Item #3

Consider Mitigations that improve local air quality and public health in the RDF, including supporting data collection efforts associated with AB 617 regarding community air protection program.

a. Learning Objective

Integrate ongoing developments in AB 617 to RAMP 2024.

b. Deliverable

PG&E will provide detail regarding mitigations in the 2024 RAMP period that are expected to reduce greenhouse gas (GHG) emissions and local air pollutants.

c. Discussion

In 2017, California took an important step to address air pollution in the most heavily burdened communities through the passage of AB 617, which directs the California Air Resources Board (CARB) to develop a community air monitoring program and a community emissions reduction program and to deploy them in the highest priority communities.

PG&E strongly supports a comprehensive, statewide air protection program and was actively engaged in the development and passage of AB 617. PG&E is working with CARB and other stakeholders through the AB 617 implementation process to ensure that the community air protection programs are successful and effective at reducing emissions in DACs. As of Q1 2024, PG&E and other stakeholders have not decided upon a mitigation for GHG emissions and local air pollutants. Therefore, there is currently no deliverable for this action item to include in the 2024 RAMP Report.

Since 2017, PG&E has actively engaged with ESJ stakeholders, including providing grants and other support to non-profits active in the AB 617 communities and monitoring the ongoing activities of AB 617.

PG&E has nine AB 617 communities, in 2023 we continued engagement in many of the communities, through the following activities:

- Providing grants to community-based organizations active in the AB 617 community activities;
- Targeting ESJ stakeholder engagement to AB 617 communities, with a current focus on Bayview-Hunters Point and surrounding areas, continuing to support their advisory committee regarding the reuse and redevelopment of our former power plant;
- We are currently planning increased engagement in West and East Oakland, South Fresno and South Stockton, with a goal to increase stakeholder engagement in all of the AB 617 communities in our service area over the next six years;
- PG&E is planning to support community-based organization in and around AB 617 communities, that have plans to continue and expand air monitoring plans and projects, whether inside or outside the formal process; and
- PG&E has labeled AB 617 communities in our GIS and other internal data sources to encourage focused consideration and engagement of AB 617 communities in our programs, projects and customer engagement.

4. Action Item #4

Evaluate how the selection of proposed mitigations in the RDF may impact climate resiliency in the DVCs.

a. Learning Objectives

Identification of climate resiliency efforts in DVCs.

b. Deliverable

PG&E will explain mitigations that impact climate resiliency in its RAMP and indicate relevant applications to DVCs.

c. Discussion

1) Resilient Together Initiative

In conformance with CPUC Decisions in the Climate Adaptation OIR (D.20-08-049), PG&E conducted extensive community outreach to DVCs as part of the Climate Adaptation Vulnerability Assessment (CAVA). On May 15, 2023, PG&E submitted this Community

Engagement Plan (CEP) to the CPUC. The results of this effort will be included in the filing of the CAVA on May 15, 2024.

The Resilient Together Initiative effort was designed to share information with DVCs on how climate change may impact the resilience of our energy system, to learn how these communities and customers are experiencing the impacts of increasingly frequent and severe climate-driven hazards, and to embed community insights and recommendations into the CAVA and the Company's future climate adaptation efforts.

Survey participants were asked about how extreme heat, power outages, wildfires/wildfire smoke, and sea level rise had the greatest impacts on their communities' experience and what they were most concerned about when experiencing these events. It was important for PG&E to understand how regional differences shape different community's views of the highest priority climate hazard impacts, so that future adaptation strategies can consider these lived experiences and concerns. Table 7-2 show the differences in how these climate hazards impact different regions and the main areas of concern.

TABLE 7-2
DVC CLIMATE HAZARD CONCERNS AND IMPACTS

Line No.	Hazard	Bay Area	Central Coast	North Coast	North Valley, Sierra	San Joaquin Valley
1	Extreme Heat	Many households lack air conditioning. Transportation to cooler places is not accessible to many people.	Lack of air conditioning and poor housing stock exacerbates extreme heat impacts for low-income communities.	Power outages compound the impact of heat waves.	Extreme heat is the main hazard of concern.	Heat impacts may be more prominent due to the prevalence of poor housing stock that is difficult to weatherize and heat island impacts.
2	Power Outages	Power outages are disruptive to daily life.		High Reports of power outages and limited use of backup power.		
3	Wildfires/ Wildfire smoke	Community members reported concerns about the health impacts from wildfire smoke.	Mountainous communities are more prone to fire hazards and subsequent mudslides.	Home insurance coverage and costs associated with evacuation events.	Concern about getting stranded in wildfire zones during active fires due to limited evacuation routes and lack of communicatio n and transportation infrastructure	
4	Sea Level Rise/ Flooding		Low-income Black and Latinx communities in low-lying areas have experienced historical flooding and face elevated risk from sea level rise.	Evacuations and post-disaster recovery is particularly fraught in the region.		

This engagement resulted in the identification of several preferred community resilience strategies. These include expanding efforts of community resilience centers and cooling centers; infrastructure improvements and grid modernization; investment in

DERs; communication, education and outreach, and forest health, vegetation management, and urban greening.

These results can be used to help identify how mitigation efforts in DVCs can alleviate the impacts of climate change and further build resilience for these communities.

5. Action Item #5

Evaluate if estimated impacts of wildfire smoke included in the RDF disproportionately impact DVCs.

a. Learning Objective

Pilot wildfire smoke analysis methodologies that can potentially lead to identifying and evaluating impacts to DVCs.

b. Deliverable

PG&E will attempt to identify if any DVCs are disproportionately impacted by wildfire smoke.

c. Discussion

D.22-12-027 requires that “Pacific Gas and Electric Company, Southern California Edison Company, San Diego Gas & Electric Company, and Southern California Gas Company shall use public studies of the health impacts of wildfire smoke available in 2023 and thereafter to structure their risk methodology related to evaluating the estimated impacts from wildfire smoke in their Environmental and Social Justice Pilot Studies.”[6] Specifically, each ESJ pilot must include the following element:

> Action Item #5: Evaluate if estimated impacts of wildfire smoke included in the RDF disproportionately impact DVCs.[7]

Finally, D.22-12-027 states “the Pilot Study should focus its evaluation of the impact of wildfire smoke on DVCs within a utility’s service territory based on utility-caused wildfires within the service territory.”[8]

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[6] D.22-12-027, pp. 67-68, OP 7.

[7] D.22-12-027, p. 67, OP 5(e).

[8] D.22-12-027, p. 50.

Pursuant to this direction, PG&E primarily used the 2022 CARB Scoping Plan and associated supporting documents to determine if utility-caused wildfire smoke disproportionately impacts DVCs/DACs within our territory. PG&E also referenced additional public studies to complement its analysis of the 2022 CARB Scoping Plan. As a result of its review, PG&E concludes:

1) CARB's study does not permit any conclusions about the impact of wildfire smoke on DVCs;
2) CARB asserts that DVCs experience greater exposure to PM2.5 pollution from all sources without identifying wildfire smoke as a significant contributor; and
3) There is consensus in other public studies that wildfire smoke impacts generally require further study.

1) CARB 2022 Scoping Plan Wildfire Smoke Review

A review of the CARB study indicates that the dataset produced by CARB is non-specific to utility-caused wildfires and spatial data cannot be derived in a reasonable manner such that the impact to DVCs may be accurately calculated. PG&E explored CARB's 2022 Draft Scoping Plan and Appendix I – Natural and Working Lands Technical Support Document.[9] CARB utilized state of the art tools to quantify wildfire smoke using multiple models layered into each other. The RHESSys model determined the carbon in vegetation for different land types: Forests, Shrublands and chaparral, Grasslands, Croplands, Developed lands, Wetlands, and Sparsely vegetated lands. The RHESSys model was layered with the WMFIRE model to simulate fire on each watershed, however, CARB notes "there is no clear agreement of what constitutes a natural fire regime in California."[10] Outputs from RHESSys are described as "generat[ing] thousands of maps that represent a single variable, each for a single time-step, for a single run, of one single watershed.

9 CARB, 2022 Scoping Plan (Nov. 2022), Appendix I - Natural and Working Lands Technical Support Document.

10 CARB, 2022 Scoping Plan (Nov. 2022), Appendix I – Natural and Working Lands Technical Support Document, p. 77.

This data has to then be processed to derive statewide time series estimates for all identified variables." CARB states that "various statewide spatial datasets are used to extrapolate the watershed level raw outputs to a statewide estimate… the computational resources, time, and storage necessary to derive spatially explicitly data [are] infeasible."[11] CARB further explains the extensive amount of computing resources necessary to perform both the modeling and scaling of RHESSys paired with WMFire resulting in petabytes of data and years of processing time.

2) CARB Review of PM2.5 Pollution Exposure to DVC

Per CARB, "[d]ue to historical inequities, under-resourced communities and communities of color are often located close to sources of toxic pollution, including chrome platers; metal recycling facilities; oil and gas operations; agricultural burning; railyards; facilities transporting, managing, or disposing of hazardous waste; and areas impacted by pesticides, among others."[12] CARB further provides the figure below, Figure 7-4,[13] identifying the sources of PM2.5 contributions to DVCs. CARB does not identify wildfire smoke as a top source of PM2.5 impacting DVCs. Considering the carbon content statewide scaling and nondescript health end points, PG&E is unable to quantitatively analyze the disproportionate impacts of wildfire smoke to DVCs.

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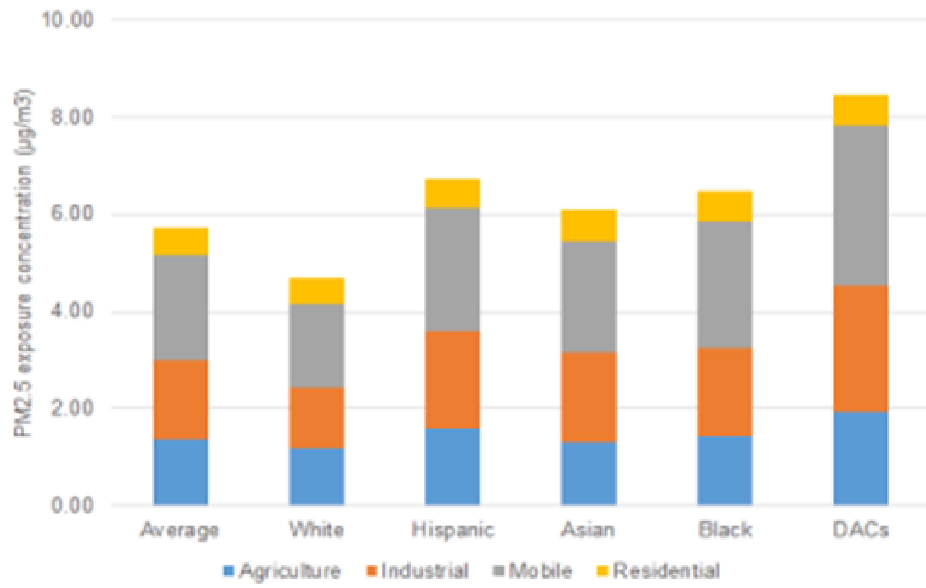
11 CARB, 2022 Scoping Plan (Nov. 2022), Appendix I – Natural and Working Lands Technical Support Document, p. 86.

12 CARB, 2022 Scoping Plan for Achieving Carbon Neutrality (Dec. 2022) (Final 2022 Scoping Plan), p.168.

13 CARB, Final 2022 Scoping Plan, p.168, Figure 3-13.

FIGURE 7-4
CARB SCOPING PLAN IDENTIFYING TOP SOURCES OF PM2.5 IMPACTING DVCS



3) Review of Other Publicly Available Studies

PG&E sought additional input regarding the impacts of wildfire smoke to DVCs through publicly available studies. Generally, PG&E found consensus and agrees that "a clearer understanding of health effects of wildfire smoke is needed"[14] and "awareness and mitigation of landscape-fire smoke exposure is important across the US, not just in regions in proximity to large wildfires."[15]

4) PG&E Recommendation Regarding Impacts of Wildfire Smoke on DVCs

As a result of its review of the CARB study and other publicly available studies as summarized above, PG&E commits again to reducing all impacts from wildfires and will continue to pursue the

14 Brian Malig, et al., Science Digest, Examining fine particulate matter and cause-specific morbidity during the 2017 North San Francisco Bay wildfires (Sept. 15, 2021), available at: <https://doi.org/10.1016/j.scitotenv.2021.147507> (accessed May 6, 2024).

15 Kelsey Bilsback, et al., GeoHealth, Estimated Mortality and Morbidity Attributable to Smoke Plumes in the United States: Not Just a Western US Problem (Aug. 21, 2021), available at: <https://doi.org/10.1029/2021GH000457> (accessed May 6, 2024).

best course for preventing further utility-caused wildfires supports through our stand “Catastrophic Wildfires Shall Stop.”

6. Action Item #6

Estimate the extent to which risk mitigation investments included in the RDF impact and benefit DVCs independently and in relation to non-DVCs in the IOU service territory.

a. Learning Objective

Initiate a process to identify potential engrained inequities in implementation of mitigations.

b. Deliverable

Using the risk analysis in Action Item #1, PG&E will compare forecasted estimates for mitigations in the LOCTM, LGUWR, Wildfire, and PSPS risks and draw relative comparisons to the impacts to DVC and non-DVC census tracts.

c. Discussion

1) LOCTM

Refer to Exhibit (PG&E-3), Chapter 1, Section B.8.a. for the results of the PSP analysis including the cost comparison result.

2) LGUWR

Refer to Exhibit (PG&E-5), Chapter 1, Section B.3.b for the results of the PSP analysis including the cost comparison result.

3) WLDFR with PSPS and EPSS

Refer to Exhibit (PG&E-4), Chapter 1, Section B.8.1. for the results of the PSP analysis including the cost comparison result.

7. Action Item #7

Enhance outreach and public participation opportunities for DVCs to meaningfully participate in risk mitigation and climate adaptation activities consistent with D.20-08-046.

a. Learning Objective

Actively seek community input to better understand potential impacts of PG&E business decisions.

b. Deliverable

PG&E provided its CAVA CEP in May 2023. PG&E will also publicly notice a workshop for this ESJ PSP, the CAVA CEP, and advance comment on PG&E's Phase I and Phase III Decisions implementation for its 2024 RAMP filing prior to the end of Q3 2023. Further, PG&E will publicly notice a workshop for the Cost-Benefit Approach and for a Pre-RAMP Workshop.

c. Discussion

1) Climate Adaptation Vulnerability Assessment Community Engagement Plan

The Resilient Together initiative was the name given to the Community Engagement efforts associated with the Company's CAVA. The goals of the Resilient Together initiative were to: learn how our most vulnerable communities experience the impacts of climate hazards and energy outages, and what strategies they need to increase their adaptive capacity at a household and community scale; share information with the communities we serve about how climate change is expected to impact the resilience of the energy system and further the conversation about how our customers would like to see us address those impacts; and to develop actionable recommendations to center community resilience and to advance community engagement practices across the Company.

The details of this community engagement with DVC communities across PG&E's service territory will be filed concurrently with this report as part of the CAVA in May 2024. This effort included the creation of five separate Regional Advisory groups, one for each PG&E region, with over 70 different Community Based Organizations. Over 40 in-depth research interviews with Community Based Organization leaders were conducted and 6,700 public survey responses were received by PG&E with an additional 2,500 responses to public outreach boards.

To utilize the feedback that was provided through this process, 20 internal PG&E teams were interviewed to assess where and how this type of community information could be used. Five separate use cases were identified; (1) direct CBO engagement efforts, (2) use in non-traditional funding applications, (3) marketing strategies, (4) use in the Company's charitable giving and advocacy work; and (5) for further aligning these communities' resilience needs with PG&E's customer focused programs. The next steps to use this community feedback data collected as part of Resilient Together initiative will be to create geospatial datasets of these community resilience needs in Quorum and Power BI, which will allow broader use across the Company.

2) ESJ PSP Public Outreach

PG&E provided and discussed the proposed ESJ PSP with its internal C-PAC with members from the CBOWG invited, the DACAG, and hosted a Public Webinar. Per request, PG&E met directly with the Community Agency for Resources, Advocacy, and Services (CARAS). PG&E provides the following table of feedback received during its outreach on the ESJ PSP.

TABLE 7-3
FEEDBACK RECEIVED DURING ESJ PSP PUBLIC OUTREACH

Line No.	Comment	Forum	Party	Date of Feedback	PG&E Response
1	Is PG&E considering de-energization and extreme heat events as a Risk	Public Webinar	CalAdvocates	7/20/2023	PG&E added Wildfire with PSPS and EPSS as a risk in the ESJ PSP
2	Power outages may disproportionately impact vulnerable communities, including low-income households, seniors, and communities of color. If the pilot programs and decision framework do not account for the specific needs and risks of these communities, it could result in further disparities and hardships	Public Webinar	CARAS	7/20/2023	PG&E added Wildfire with PSPS and EPSS as a risk in the ESJ PSP
3	The programs may require expensive and complex technologies, which could exclude low-income households and those who don't have access to reliable internet connections or equipment to participate	Public Webinar	CARAS	7/20/2023	PG&E included programs supporting people with low income in Action Item #2
4	Without clear and transparent communication and outreach to vulnerable communities, there could be a lack of awareness and understanding of the programs, resulting in further inequities and mistrust	Public Webinar	CARAS	7/20/2023	PG&E did not identify a change that could be made in the ESJ PSP as a result of this feedback.

TABLE 7-3
FEEDBACK RECEIVED DURING ESJ PSP PUBLIC OUTREACH
(CONTINUED)

Line No.	Comment	Forum	Party	Date of Feedback	PG&E Response
5	The Risk-Based Decision Framework may prioritize cost savings over public safety, especially if decisions are based on incomplete or outdated data. This could result in communities being at a higher risk of power outages, wildfires, and other hazards.	Public Webinar	CARAS	7/20/2023	PG&E did not identify a change that could be made in the ESJ PSP as a result of this feedback. PG&E believes this feedback should be considered in the RDF rulemaking.
6	The programs and decision framework could exacerbate existing health disparities. For example, power outages can impact the ability of vulnerable populations to access medical care and essential medications that require refrigeration	Public Webinar	CARAS	7/20/2023	PG&E did not identify a change that could be made in the ESJ PSP as a result of this feedback. PG&E recommends customers enroll in its medical baseline program.
7	PSPS should be modeled as a separate risk and included in the ESJ Pilot	Public Webinar	SBUA	7/20/2023	PG&E included PSPS and EPSS as a sub-risk to Wildfire and has discussed its decision to include PSPS and EPSS as sub-risks in Public Workshop #1 on 2/7/24
8	Has PG&E considered battery usage and charging from the grid and how that influences peak demand and potentially helps optimize Net Energy Metering (NEM). Enabling DVCs to recharge from the grid may help resilience	Public Webinar	SBUA	7/20/2023	PG&E did not identify a change to the current ESJ PSP. PG&E reached out to its EPIC program representatives and discussed ongoing battery programs. PG&E is unable to include the identified programs at this time but will continue to pursue.

TABLE 7-3
FEEDBACK RECEIVED DURING ESJ PSP PUBLIC OUTREACH
(CONTINUED)

Line No.	Comment	Forum	Party	Date of Feedback	PG&E Response
9	The risk reduction benefits offered by the MIP and the CMEP can be integrated in the RAMP: 1) Quantify the risk reduction benefits: The MIP and CMEP provide financial incentives to encourage the development of microgrids, which can help reduce the risk of power outages during extreme weather events. One way to represent this in RAMP is by quantifying the reduction in risk that a microgrid would provide and assessing the cost-effectiveness of the program. 2) Incorporate microgrid technology into RAMP: The technology used in microgrids, such as energy storage and smart controls, can be incorporated into RAMP to enhance its ability to predict and prevent power outages. This would help identify the areas that are most at risk and prioritize the deployment of the microgrids accordingly. 3) Consider the benefits of community engagement: Both MIP and CMEP prioritize community engagement and collaboration, which could be used to build stronger relationships with customers and local communities. This could increase the overall resilience of the power grid by promoting the adoption of renewable energy sources and energy efficiency measures. Especially tapping into non-profits who can provide data via surveys gathered from the community, providing that PG&E provides funding to the non-profits. This partnership is crucial to bridge the gap with community and PG&E and other stakeholders.	Public Webinar	SBUA	7/20/2023	PG&E agrees with the feedback, however, specific projects to include for risk reduction are not available at this time. PG&E will continue to work with the MIP and CMEP program owners to include any identified projects in its risk framework.

TABLE 7-3
FEEDBACK RECEIVED DURING ESJ PSP PUBLIC OUTREACH
(CONTINUED)

Line No.	Comment	Forum	Party	Date of Feedback	PG&E Response
	4) Evaluate the long-term cost savings: The MIP and CMEP investments may cost more upfront but could offer long-term cost savings by reducing the risk of power outages and thus avoiding the need for costly repairs and maintenance. These long-term benefits can be evaluated in RAMP to assess the overall return on investment. In summary, RAMP can represent the risk reduction benefits offered by MIP and CMEP by quantifying the benefits, incorporating microgrid technology, promoting community engagement, and evaluating the long-term cost savings. This will help identify the most effective strategies for reducing risk and improving the resilience of the power grid for all customers, especially the most vulnerable.				
10	How has outreach been to small businesses and how will that be represented in our upcoming CAVA?	Public Webinar	SBUA	7/20/2023	PG&E provides its CAVA outreach and response to these questions in Action Item 4 of the ESJ PSP.
11	GHG impacts affect DVCs; can we consider that along with the existing [wildfire smoke] studies?	Public Webinar	SBUA	7/20/2023	PG&E has taken this question into consideration but is unable to quantify these impacts at this time.
12	Would it be possible to do a lower cost alternative using past studies that aren't out of date? Should you partner with an academic organization that is trying to accomplish the same thing?	Public Webinar	CalAdvocates	7/20/2023	Per D.22-12-027, IOUs were recommended to use public studies available in 2023. PG&E has done so and researched broadly and did not use out of date studies in its resolution of Action Item 5. However, an IOU partnership with an academic organization was not included for this Action Item.

TABLE 7-3
FEEDBACK RECEIVED DURING ESJ PSP PUBLIC OUTREACH
(CONTINUED)

Line No.	Comment	Forum	Party	Date of Feedback	PG&E Response
13	Consider the impacts of short-term GHG emissions from wildfire smoke and also the destruction of climate sequestration resources by wildfire. The Dept. of Forestry, CARB, and the California Chapter of the Nature Conservancy has done work on this.	Public Webinar	CalAdvocates	7/20/2023	PG&E has taken this question into consideration but is unable to quantify these impacts at this time.
14	What data is being collected from Resilience Together and what insights are being gained? How will the data be used to make meaningful impact?	Public Webinar	CARAS	7/20/2023	PG&E provides its learnings from the Resilient Together initiative in Action Item 4.
15	I think it would be interesting to look at some of the health impacts not just on a total $ basis (or $ inside or outside of DVCs) but also $/capita. For example, if you're looking at wildfire smoke, not just what are the total PM2.5 health impacts, but what are they *per person* (or per 1000 people or whatever makes sense) inside or outside of DVCs? What does this look like distributionally across the state? Some areas might have relatively low total populations, but very high impact for each individual in that location for a given event.	DACAG	PSE Healthy Energy	6/16/2023	PG&E has taken this question into consideration but is unable to quantify these impacts at this time.
16	How will PG&E identify and assess the potential impacts in DVC areas	C-PAC	Valley CAN	6/15/2023	PG&E describes the methodology used to identify and assess potential impacts in each respective risk chapter section on Potential ESJ Consequences

TABLE 7-3
FEEDBACK RECEIVED DURING ESJ PSP PUBLIC OUTREACH
(CONTINUED)

Line No.	Comment	Forum	Party	Date of Feedback	PG&E Response
17	If the risk is disproportionate from a particular risk, would that take the analysis in a different direction or change strategy on mitigation?	C-PAC	Valley CAN	6/15/2023	PG&E continues to evaluate how to incorporate insights gained from implementation of the ESJ Pilot Study in its prioritization but does not have changes in strategy to discuss at this time.
18	What mitigations are you looking at in response to the risk? How is PG&E evaluating the risk or determining how risky it is to a particular community?	C-PAC	Valley CAN	6/15/2023	The impact of risks to ESJ communities as well as the benefits from mitigations are discussed in section B.1. as well as each respective risk chapter.
19	Are the difficulties a community may face in recovering taken into consideration?	C-PAC	Valley CAN	6/15/2023	At this time, PG&E does not have data on the difficulties a community may face in recovering from a risk. PG&E has been learning about efforts outside of PG&E are underway to attempt to understand this, e.g., the POET tool supplement to the ICE calculator.
20	Can PG&E provide more information on which tactics PG&E is looking at for AB 617	C-PAC	Valley CAN	6/15/2023	PG&E provides its AB 617 strategy in response to Action Item 3.
21	If [AB 617 is for]monitoring only, how will it be used to narrow down useful data?	C-PAC	Valley CAN	6/15/2023	PG&E provides its AB 617 strategy in response to Action Item 3.
22	Can the C-PAC get a briefing on PG&E's Resilient Together? Are DVCs at greater risk of extreme scenarios? If the risks are greater, the mitigations should be planned accordingly	C-PAC	Valley CAN	6/15/2023	Resilient Together was added to the C-PAC's agenda item list.
23	Need to have a conversation regarding risks in the DVC, which could further the conversation and addressing the known risks and reduce those risks in the future and could be informative to the community	C-PAC	Unable to identify at time of feedback	6/15/2023	PG&E continues to seek input from external community-representing parties in the C-PAC and other outreach efforts. See section B.7. for Action Item #7 detailing continued outreach to DVCs.

TABLE 7-3
FEEDBACK RECEIVED DURING ESJ PSP PUBLIC OUTREACH
(CONTINUED)

Line No.	Comment	Forum	Party	Date of Feedback	PG&E Response
24	Should have a conversation on what the real risks are facing these communities and where the most effective investments could be in addressing the known risks there and what could be most effective now to reduce those risks in the future.	C-PAC	Unable to identify at time of feedback	6/15/2023	PG&E continues to seek input from external community-representing parties in the C-PAC and other outreach efforts.
25	What is the value of this [wildfire smoke analysis]? Is there a use of this data that would make it easier to mitigate impacts on DVCs	C-PAC	Unable to identify at time of feedback	6/15/2023	PG&E provides its wildfire smoke impact analysis in its response to Action Item 5.
26	Continued community engagement in the ESJ PSP is critical. Consider direct outreach in addition to the requirements in the Phase II decision.	Direct Outreach	CARAS	7/25/2023	PG&E continues to seek input from external community-representing parties in the C-PAC and other outreach efforts.
27	Consider surveys in the pre-RAMP workshops	Direct Outreach	CARAS	7/25/2023	PG&E coordinates with Commission Staff in hosting the pre-RAMP workshops and has not find an application for surveys in the workshops.
28	PSPS needs better explanation and forewarning to the communities.	Direct Outreach	CARAS	7/25/2023	PG&E appreciates the feedback and provides as much advanced warning as is capable at this time.
29	Surveys need to be submitted with explanations as to why the communities' responses are critical to improving their experience.	Direct Outreach	CARAS	7/25/2023	PG&E will attempt to ensure its surveys engage recipients appropriately.
30	Consider outreach for developing the White Paper post implementation of the ESJ PSP in the RAMP	Direct Outreach	PG&E	7/25/2023	PG&E will consider the feedback but is not yet developing the whitepaper at this time.

3) Pre-RAMP Workshops

PG&E hosted two public Pre-RAMP Workshops:

TABLE 7-4
PRE-RAMP WORKSHOPS

Line No.	Date	Topic
1	February 7, 2024	Risk Selection, Scaling, Intro to select risks
2	April 11, 2024	Risk Model Framework and Cost-Benefit Approach

4) Community Perspectives Advisory Council

PG&E is committed to providing opportunities and forums to learn from Community-Based Organizations (CBO) and understand their perspectives and recommendations for PG&E's programs and services. In 2022, as part of PG&E's effort to expand and deepen its CBO partnerships and engage CBOs across the service territory to assist in reaching customers and providing households education and outreach, PG&E created a new C-PAC. This was a proactive effort, that was not required by any Commission directive. PG&E's intent with the C-PAC is to increase the diversity of CBO perspectives providing input on the issues and solutions across the service territory. While the topics for the Council are wide ranging, they are largely focused on resiliency, and increasing equity and access to customer and emerging technology programs and projects.

C-PAC members are CBO representatives that have been nominated as leaders in their organization (i.e., Executive Director, Director, Head Pastor, or equivalent) and have subject matter expertise that include, but are not limited to: income-qualified programs and low-income specific issues (i.e., access, affordability of utility service, etc.), understanding unique needs of ESJ communities in terms of energy and resiliency needs, on-the-ground work in priority communities, distributed generation and net energy metering, emerging technologies, pilot programs in DACs and in other priority communities, electric vehicles and clean energy transportation, job training and workforce development, and climate adaptation, sustainability, and resiliency planning.

PG&E appreciates the valuable community and stakeholder input it has received from C-PAC members since its inception in 2022 and plans to continue the forum through at least 2024. PG&E will solicit feedback from C-PAC members to determine interest for future continuation of the C-PAC beyond 2024.

Application: 24-05-
(U 39 G)
Exhibit No.: (PG&E-3)
Date: May 15, 2024
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT

EXHIBIT (PG&E-3)

GAS OPERATIONS

PACIFIC GAS AND ELECTRIC COMPANY
2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
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PACIFIC GAS AND ELECTRIC COMPANY
RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 1
RISK ASSESSMENT AND MITIGATION STRATEGY: LOSS OF CONTAINMENT ON GAS TRANSMISSION PIPELINE

A. Executive Summary

Loss of Containment on Gas Transmission Pipeline (LOCTM) refers to a failure of a gas transmission pipeline resulting in a Loss of Containment (LOC), with or without ignition, that could lead to significant impact on public safety, employee safety, contractor safety, property damage, environmental damage, financial loss, and the inability to deliver natural gas to customers. Failure of a gas transmission pipeline includes both pipeline leak and pipeline rupture. The drivers for this risk event are: third-party damage; External Corrosion (EC); manufacturing defects (including Selective Seam Weld Corrosion (SSWC)); construction threats; Internal Corrosion (IC); Weather-Related and Outside Force (WROF) threats; equipment failure; incorrect operations; and stress Corrosion Cracking (SCC). The cross-cutting factors which impact the risk are Physical Attack, Records and Information Management (RIM) and Seismic.

Exposure to this risk is based on approximately 6,426 miles of transmission pipeline in the Pacific Gas and Electric Company (PG&E or the Company) system. A LOCTM risk event is expected to occur 3.7 times a year, based on the risk model results. Third-party damage is the highest contributor to the frequency of this risk, accounting for 39 percent of the events. EC is the second dominant key driver which accounts for 38 percent of events based on frequency. Based on percent of risk, Third-Party Damage is the highest contributor, accounting for 59 percent of the risk, followed by the Seismic cross-cutting factor accounting for 23 percent of the risk and EC accounting for 10 percent.[1] The remaining risk drivers account for an additional 8 percent of the risk. Pipeline rupture accounts for 99 percent of the risk outcomes and pipeline leak accounts for the remaining 1 percent.

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[1] EC accounts for 38 percent of events accounted for in the LOCTM risk model, and 10 percent of risk. The lower overall risk percentage result is due to the probability that EC events are more likely to leak than rupture.

The mitigations PG&E plans to implement from 2027-2030 are designed to address these key risk drivers and outcomes.

PG&E identified 24 tranches for this risk, a significant increase from the 2020 Risk Assessment and Mitigation Phase (RAMP) model which only had 4 tranches. Each tranche represents a group of transmission assets that are intended to have similar risk profiles. Tranches were grouped by six likelihood (of LOC) and four consequences categories, resulting in 24 tranches.

LOCTM has the second-highest 2027 Test Year Baseline Safety Risk Score ($138.5 million) and tenth-highest 2027 Test Year Baseline Total Risk Score ($186.1 million) of PG&E's 32 Corporate Risk Register risks. For PG&E's proposed mitigations, Vintage Pipe Replacement has the highest Cost-Benefit Ratio (CBR) and the highest total risk reduction score.

1. Risk Overview

TABLE 1-1
RISK DEFINITION, SCOPE, AND DATA SOURCES

Line No.	Risk Name	LOCTM
1	Definition	Failure of a gas transmission pipeline resulting in a LOC, with or without ignition, that could lead to significant impact on public safety, employee safety, contractor safety, property damage, financial loss, or the inability to deliver natural gas to customers. Failure of a gas transmission pipeline includes both pipeline leak and pipeline rupture.
2	In Scope	Failure of a transmission pipeline that leads to a significant LOC (leak or rupture). Significant is defined as a LOC that results in an injury requiring in-patient hospitalization, a fatality, or total costs valued at $50,000 or more, measured in 1984 dollars. Pipeline and Hazardous Materials Safety Administration (PHMSA) 49 Code of Federal Regulations (CFR) Part 191.3 lists the leak reporting criteria, which is used in the RAMP LOCTM model.
3	Out of Scope	A LOC driven by large overpressure events, LOC on distribution assets.
4	Data Quantification Sources	PHMSA reports from 1984-2023; Output from Transmission Integrity Management Program (TIMP) operational risk model – Working Assessment Plan (WAP) data based on TIMP 2022 risk run result; Gas Quarterly Incident (GQI) data: 2010-2022

PG&E's natural gas transmission system consists of approximately 6,426 miles of transmission pipeline. Transmission pipeline and associated major components (including transmission valves) transport gas from receipt points into PG&E’s natural gas transmission system until the gas arrives at a distribution center, a storage facility or a large customer (not downstream of a distribution center). The average age of PG&E’s transmission pipe is approximately 55 years, with current geographic and other component data held on a Geographic Information System (GIS). About 24.4 percent of PG&E’s transmission system miles are in High Consequence Areas (HCA) and additionally about 12.6 percent are in Moderate Consequence Areas (MCA). Threats to transmission pipe include third-party damage, internal and EC, construction threats, WROFs, manufacturing defects, SCC, equipment failure, and incorrect operations. These threats to the assets in the transmission pipe asset family could lead to LOC (leak or rupture) that would result in an uncontrolled gas release leading to potential public, contractor and/or employee safety issues, outages, and/or property damage.

PG&E manages transmission pipeline risk through its TIMP. TIMP is the program in which PG&E identifies, prioritizes, assesses, evaluates, repairs, and validates the integrity of its gas transmission pipeline that could, in the event of a leak or rupture, impact public safety.

Examples of the type of work PG&E performs in the TIMP to manage transmission asset risk include In-Line Inspection (ILI), Direct Assessment (DA), strength testing, vintage pipe replacement, earthquake fault crossing assessment and mitigation, geo-hazard threat identification and mitigation, emergency response programs, class location changes, shallow and exposed pipe assessment and mitigation, gas gathering, programs to support integrity management and pipe investigations and field engineering.

PG&E also manages transmission asset risk through its damage prevention and leak survey programs. PG&E conducts damage prevention activities on the gas transmission pipeline system by implementing locate and mark and standby activities, as well as Public Awareness Programs (PAP). PG&E conducts leak surveys on the gas transmission pipeline system by implementing foot, aerial and mobile leak survey to meet regulatory requirements. While pipeline leaks only account for a small portion of the transmission pipeline risk (discussed in Section B.7 below), it is important to include leak monitoring and management in the risk analysis so that PG&E has a holistic view of the potential risks to the gas transmission pipeline system.

B. Risk Assessment

1. Background and Evolution

The 2024 LOCTM risk model has continued to improve since PG&E's 2020 RAMP. Two improvements since the 2020 RAMP model are more granular tranches and improved data inputs. The 2024 model more accurately represents PG&E's transmission pipeline system because it expands the count of tranches from 4 to 24, and because it is based on PG&E data (where available). In the 2020 RAMP, PG&E identified nine risk drivers based on the American Society of Mechanical Engineers (ASME) B31.8S Standard. B31.8S is designed to provide pipeline operators with the information necessary to develop and implement an effective integrity management program using proven industry practices and processes.[2]

The 2024 RAMP includes the same risk drivers as the 2020 RAMP and three cross-cutting factor risk drivers: Physical Attack, RIM and Seismic. PG&E's analysis was informed by PHMSA Incident Report data (updated through June 2023), Gas Transmission Incident Reports, and PG&E's current transmission pipeline asset data for pipeline integrity, High- and Medium-Consequence Areas (MCA), people impacted within the Potential Impact Radius, and customers impacted downstream.

In the 2024 RAMP, PG&E transitions from considering transmission pipeline risk tranches in terms of Impacted Occupancy Count (IOC), which resulted in four tranches, to considering it in terms of six primary threats in combination with four consequence magnitude indicators, resulting in 24 tranches. This change allows for better alignment with PG&E's transmission integrity management risk model. The consequence magnitude factors include HCA and MCA, which focus on the potential consequence of a risk event to clusters of structures or gatherings of people, and IOC, which focuses on the potential impact of a risk event to individuals living and working around a transmission pipeline. PG&E is using HCA, MCA and IOC in tranche consequence because these allow for a more granular and accurate representation of potential safety impacts based on the presence of both structures and people in the pipeline vicinity.

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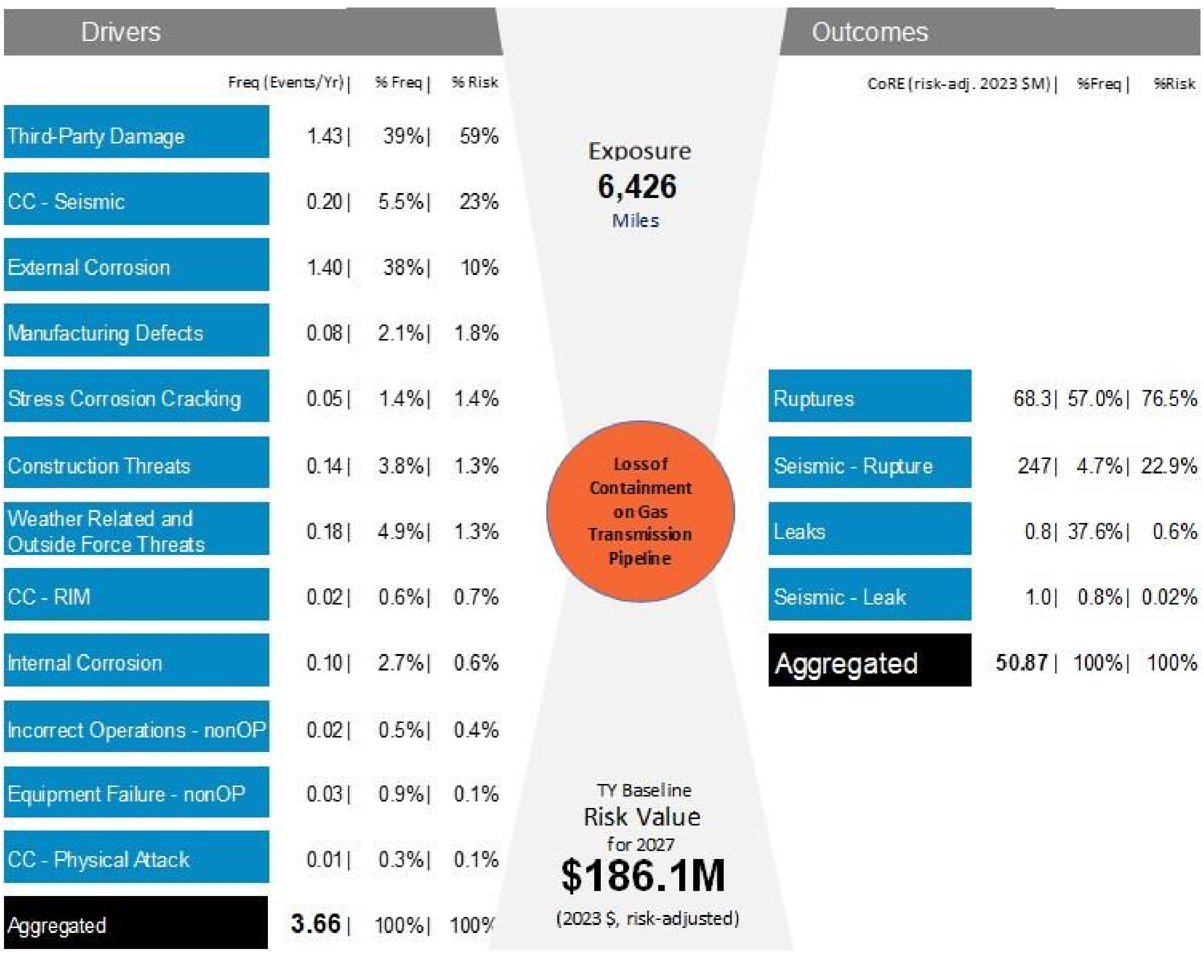
2 The ASME, ASME B31.8S – 2018, "Managing System Integrity of Gas Pipelines."

Finally, in Decision (D.) 23-12-003, p. 48, Ordering Paragraph 4, the California Public Utilities Commission (CPUC or Commission)-approved PG&E's Transmission Definition change. The analysis in this chapter does not incorporate this change. PG&E is in process of analyzing this change and it will include any impacts in its 2027 General Rate Case (GRC) filing.

2. Risk Bow Tie

FIGURE 1-1
RISK BOW TIE



a. Difference from 2020 Risk Bow Tie

The 2024 RAMP bow tie (see Figure 1-1 above) utilizes the same format as presented in 2020 RAMP bowtie and the 2023 GRC bowtie, with changes noted below.

1) Drivers

The 2024 bow tie includes the same risk drivers as the 2020 RAMP bow tie, with one exception: the removal of the CC-SQWF risk driver.

2) Outcomes

The 2024 bow tie displays possible outcomes for each LOC event. The 2020 RAMP bow tie included eight outcomes. In both the 2023 GRC and 2024 RAMP, the outcomes were reduced from eight to four that include pipeline leak, pipeline rupture, seismic-leak, and seismic-rupture. Ruptures or leaks due to cyber-attacks or Information Technology (IT) asset failure were removed from the list of outcomes.

3) Consequences

2024 RAMP uses the same three consequence types as 2020 RAMP: safety, gas reliability and financial.

3. Exposure to Risk

PG&E's natural gas transmission system is inherently hazardous with the identified risks that could lead to a LOC event. PG&E measured the risk exposure as the number of miles of transmission pipeline owned and operated by PG&E. The total exposure used in the model is approximately 6,426 miles of transmission pipeline for 2023-2030.

4. Tranches

PG&E identified 24 tranches for the LOCTM risk. Each tranche represents a group of transmission assets that are determined to have a similar risk profile associated with Likelihood of Failure (LOF) and Consequence of Failure (COF) LOCTM events. Assets were assigned tranches based on six LOF categories and four COF categories, resulting in 24 tranches. This tranche methodology represents a more granular approach than the four tranches previously presented in the 2020 RAMP and the 2023 GRC. Subject Matter Experts (SME) expect that areas with a higher consequence would have a higher risk on average.

The six LOF categories include:

- <u>L1</u>: Shallow/exposed pipe.
- <u>L2</u>: Geohazard pipe.

- L3: Potential SCC/SSWC pipe.
- L4: Potential IC pipe.
- L5: Potential manufacturing defect pipe.
- L6: All other pipe.

The four COF categories include:

- C1: HCA.
- C2: MCA.
- C3: IOC >0 and rupture mode on Non-HCA/MCA.
- C4: IOC = 0 or leak mode on Non-HCA/MCA.

Table 1-2 below depicts the six LOF categories and four COF categories form a 6x4 LOF/COF matrix where the pipe was prioritized (placed into tranches) as follows: L2, L3, L5, L1, L4, L6. For example, all pipes subject to Geohazard LOF were placed in L2, and all pipe susceptible to SCC/SSWC LOF were placed in L3, except for the pipe segments already placed in L2. Regardless of the LOF into which the pipe is prioritized, the risks for all drivers associated with the pipe are summed up. For example, the risk score calculated for the Geohazard tranches includes the risks of all drivers for the pipe in the Geohazard tranches, not just the risk associated with the Seismic and WROF drivers.

TABLE 1-2
TRANCHE LIKELIHOOD AND CONSEQUENCE MATRIX

Line No.	LOF/ COF Matrix	C1	C2	C3	C4
1	L1	L1C1	L1C2	L1C3	L1C4
2	L2	L2C1	L2C2	L2C3	L2C4
3	L3	L3C1	L3C2	L3C3	L3C4
4	L4	L4C1	L4C2	L4C3	L4C4
5	L5	L5C1	L5C2	L5C3	L5C4
6	L6	L6C1	L6C2	L6C3	L6C4

The 24 tranche names and exposure (expressed in miles) based on the above LOF/COF combinations are described below in Table 1-3:

TABLE 1-3
TRANCHE DESCRIPTIONS AND EXPOSURE
(MILES)

Line No.	Tranche ID	Tranche	Miles
1	L1C1	Shallow/Exposed Pipe and HCA	160
2	L1C2	Shallow/Exposed Pipe and MCA	93
3	L1C3	Shallow/Exposed Pipe and (IOC > 0 & rupture mode on Non-HCA/MCA)	17
4	L1C4	Shallow/Exposed Pipe and (IOC = 0 or leak mode on Non-HCA/MCA)	400
5	L2C1	Geohazard Pipe and HCA	366
6	L2C2	Geohazard Pipe and MCA	132
7	L2C3	Geohazard Pipe and (IOC > 0 & rupture mode on Non-HCA/MCA)	28
8	L2C4	Geohazard Pipe and (IOC = 0 or leak mode on Non-HCA/MCA)	854
9	L3C1	Potential SCC/SSWC Pipe and HCA	51
10	L3C2	Potential SCC/SSWC Pipe and MCA	32
11	L3C3	Potential SCC/SSWC Pipe and (IOC > 0 & rupture mode on Non-HCA/MCA)	14
12	L3C4	Potential SCC/SSWC Pipe and (IOC = 0 or leak mode on Non-HCA/MCA)	332
13	L4C1	Potential IC Pipe and HCA	202
14	L4C2	Potential IC Pipe and MCA	144
15	L4C3	Potential IC Pipe and (IOC > 0 & rupture mode on Non-HCA/MCA)	27
16	L4C4	Potential IC Pipe and (IOC = 0 or leak mode on Non-HCA/MCA)	556
17	L5C1	Potential Manufacturing Defect Pipe and HCA	195
18	L5C2	Potential Manufacturing Defect Pipe and MCA	154
19	L5C3	Potential Manufacturing Defect Pipe and (IOC > 0 & rupture mode on Non-HCA/MCA)	34
20	L5C4	Potential Manufacturing Defect Pipe and (IOC = 0 or leak mode on Non-HCA/MCA)	901
21	L6C1	All Other Pipe and HCA	603
22	L6C2	All Other Pipe and MCA	239
23	L6C3	All Other Pipe and (IOC > 0 & rupture mode on Non-HCA/MCA)	47
24	L6C4	All Other Pipe and (IOC = 0 or leak mode on Non-HCA/MCA)	845
25	Total		6,426

Using GIS and other tools, tranches are calculated from the TIMP Risk Model. The main purpose of using tranches is to improve understanding of how likelihoods and consequences of failure can inform risk-based decision making. Likelihood factors can help inform the probability of a LOC from a specific threat, manifested as pipeline leaks or ruptures per mile per year for pipe segments within that threat's tranche. Consequence factors can help inform what the distribution of consequences are when pipe experiences a LOC.

The 24 tranches allow for more targeted assessment by tranche to identify and reflect awareness of investments in risk reduction activities. Both LOF and COF categories are drawn from threat-specific likelihood and consequence area data used for TIMP's program scoping and prioritization.

Tranches are influenced by asset health attributes. For example, all TIMP threats incorporate asset health data, from sources such as ILI, inspection digs, leak repairs, and DA. PG&E will continue to explore asset health for future tranche categories as risk modeling continues to mature.

Table 1-4 below shows the tranche-level results of the risk analysis for the 2027 test year baseline risk values. The six tranches within HCA (C1) represent 84 percent of overall risk. The Geohazard Pipe and HCA tranche (L2C1) presents the highest risk score with 43.1 percent of total risk for LOCTM. Geohazard Pipe aligns with the CC-Seismic and WROF threats risk drivers. Numerous controls focus on controlling this risk, in particular LOCTM-C001 – Geo Hazard Threat Identification and Mitigation and LOCTM-C004 – Earthquake Fault Crossings. The controls associated with TIMP focus on pipe located in HCA, particularly LOCTM-C005 – ILI, LOCTM-C022 – DA, and LOCTM-C026 – TIMP Strength Testing.

TABLE 1-4
PERCENT EXPOSURE, RISK SCORE, AND PERCENT RISK BY TRANCHE

Line No.	Tranche	Exposure (%)	Safety Risk Value ($M)	Reliability Risk Value ($M)	Financial Risk Value ($M)	Aggregated Risk Value ($M)	Risk (%)
1	Shallow/Exposed Pipe and HCA	2.5%	16.93	0.43	4.17	21.53	11.6%
2	Shallow/Exposed Pipe and MCA	1.4%	1.10	0.18	0.07	1.35	0.7%
3	Shallow/Exposed Pipe and (IOC > 0 & rupture mode on Non-HCA/MCA)	0.3%	0.02	0.02	0.01	0.05	0.0%
4	Shallow/Exposed Pipe and (IOC = 0 or leak mode on Non-HCA/MCA)	6.2%	0.55	0.61	0.20	1.35	0.7%
5	Geohazard Pipe and HCA	5.7%	69.70	2.68	7.84	80.23	43.1%
6	Geohazard Pipe and MCA	2.1%	1.63	0.28	0.07	1.98	1.1%
7	Geohazard Pipe and (IOC > 0 & rupture mode on Non-HCA/MCA)	0.4%	0.15	0.21	0.05	0.41	0.2%
8	Geohazard Pipe and (IOC = 0 or leak mode on Non-HCA/MCA)	13.3%	1.46	6.76	1.34	9.56	5.1%
9	Potential SCC/SSWC Pipe and HCA	0.8%	2.37	0.16	0.72	3.24	1.7%
10	Potential SCC/SSWC Pipe and MCA	0.5%	0.05	0.40	0.01	0.47	0.3%
11	Potential SCC/SSWC Pipe and (IOC > 0 & rupture mode on Non-HCA/MCA)	0.2%	0.01	0.12	0.00	0.14	0.1%
12	Potential SCC/SSWC Pipe and (IOC = 0 or leak mode on Non-HCA/MCA)	5.2%	0.09	3.36	0.09	3.55	1.9%
13	Potential IC Pipe and HCA	3.1%	7.89	0.45	1.86	10.21	5.5%
14	Potential IC Pipe and MCA	2.2%	0.94	0.95	0.04	1.92	1.0%
15	Potential IC Pipe and (IOC > 0 & rupture mode on Non-HCA/MCA)	0.4%	0.13	0.09	0.01	0.23	0.1%
16	Potential IC Pipe and (IOC = 0 or leak mode on Non-HCA/MCA)	8.6%	0.19	1.42	0.18	1.80	1.0%
17	Potential Manufacturing Defect Pipe and HCA	3.0%	8.29	0.22	2.54	11.05	5.9%
18	Potential Manufacturing Defect Pipe and MCA	2.4%	1.00	0.12	0.06	1.17	0.6%
19	Potential Manufacturing Defect Pipe and (IOC > 0 & rupture mode on Non-HCA/MCA)	0.5%	0.05	0.05	0.01	0.11	0.1%
20	Potential Manufacturing Defect Pipe and (IOC = 0 or leak mode on Non-HCA/MCA)	14.0%	0.53	1.99	0.46	2.98	1.6%
21	All Other Pipe and HCA	9.4%	23.72	0.39	6.02	30.12	16.2%
22	All Other Pipe and MCA	3.7%	1.14	0.13	0.07	1.34	0.7%
23	All Other Pipe and (IOC > 0 & rupture mode on Non-HCA/MCA)	0.7%	0.05	0.03	0.01	0.10	0.1%
24	All Other Pipe and (IOC = 0 or leak mode on Non-HCA/MCA)	13.2%	0.50	0.50	0.24	1.23	0.7%
25	Total	100%	138.51	21.54	26.07	186.13	100%

5. Drivers and Associated Frequency

PG&E has identified nine primary risk drivers for its LOCTM risk. Risk drivers eight and nine, Incorrect Operations and Equipment Failure, only include the contribution associated with non-overpressure events. The contribution associated with overpressure events is captured in the other gas risk model, Large Overpressure Event Downstream of Gas Measurement and Control Facility (Exhibit (PG&E-3), Chapter 3). Each driver and its associated 2027 test-year estimated frequency are discussed below.

- D1 – Third-Party Damage: Refers to pipeline damage inflicted by first, second, or third parties through digging activities. Third-party damage related rupture incidents accounts for 1.43 (39 percent) of the 3.7 expected annual number of LOC events.[3]
- D2 – External Corrosion: Refers to the deterioration of the outside of the steel pipe that results from reaction with the outside environment (i.e., soil, water). Over time, EC can reduce the wall thickness of the pipe, making the pipe weaker and more susceptible to other threats. EC accounts for 1.4 (38 percent) of the 3.7 expected annual number of LOC events.
- D3 – WROFs: Refers to water crossings, unstable soil, erosion, heavy rains, and floods. WROFs accounts for 0.18 (4.9 percent) of the 3.7 expected number of LOC events. Seismic activity was excluded from this driver, as it is considered a cross-cutting factor for the 2024 RAMP.
- D4 – Construction Threats: Refers to a connection between two segments of pipe. Construction Threats accounts for 0.14 (3.8 percent) of the 3.7 expected annual number of LOC events.
- D5 – Internal Corrosion: Refers to corrosion of the internal wall of steel transmission pipelines following exposure to water and/or contaminants in the gas. The extent of the corrosion damage and resultant threat depends on the operating conditions of the pipeline and the particular

3 The risk model frequencies account for both leaks and ruptures under the broad description “loss of containment” event.

corrosive constituents within the pipe. IC accounts for 0.10 (2.7 percent) of the 3.7 expected annual number of LOC events.

- D6 – Manufacturing Defects: Refers to longitudinal seam defects caused by flaws in the welding of the pipe seam and/or pipe body defects caused by various steel impurities. It also includes SSWC. Manufacturing defects accounts for 0.08 (2.1 percent) of the 3.7 expected annual number of LOC events.
- D7 – Stress Corrosion Cracking: Refers to cracking from the combined influence of tensile stress and a corrosive environment. SCC accounts for 0.05 (1.4 percent) of the 3.7 average expected number of LOC events.
- D8 – Incorrect Operations: Refers to any activity, or omission of an activity, by PG&E personnel that could adversely impact the safety or reliability of the pipeline. Events due to incorrect operations result from work procedure errors or human performance factors. Only non-overpressure incidents were included in this driver. Incorrect operations accounts for 0.02 (0.5 percent) of the 3.7 expected annual number of LOC events.
- D9 – Equipment Failure: Equipment refers to pipeline facilities, other than pipe and pipe components, such as gaskets and O-rings, and control valve failure. Only non-overpressure incidents were included in this risk driver. Equipment failure accounts for 0.03 (0.9 percent) of the 3.7 expected annual number of LOC events.

To model this risk, PG&E utilized internal gas frequency and consequence data (derived from PG&E's current transmission pipeline conditions and location) and PHMSA data from 1984 through June 2023. The PHMSA data includes Gas Transmission incident reports from 1984 to June 2023.[4] The PHMSA data was used to supplement PG&E data where driver frequencies were unavailable from the TIMP risk model.

PG&E's data regarding failure likelihood for ruptures is derived from the current condition of the transmission pipeline system. The failure likelihood

4 PHMSA reporting requirements for incidents differed over these different periods of time (1984-2002, 2002-2010, and June 2010-2023).

algorithm addresses the LOF due to each of the risk drivers. For some threats, such as EC and IC, failure likelihood is calculated using probabilistic methods when ILI data are available. Where it is not possible to estimate failure likelihood by using probabilistic methods, a quantitative estimate is derived by means of an adjustment factor approach, applied against base case industry or PG&E failure likelihood statistics.

PG&E's failure likelihood for leaks is derived using a similar approach as for ruptures except for Equipment Failure, Incorrect Operations, and the cross-cutting risk drivers. For these risk driver frequencies, adjustment factors/ratios from PHMSA data, PG&E failure data, and SME input are used.

6. Climate Adaptation Vulnerability Assessment Results

PG&E designed the Climate Adaptation Vulnerability Assessment (CAVA) to be consistent with the CPUC's Final Ruling on Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Change Adaptation (R.18-04-019). The methodology outlined by D.20-08-046 requires utilities to perform an assessment of all assets, operations and services that will be impacted by future risks from climate change related to changes in temperatures, precipitation & flooding, sea level rise, wildfire, and drought driven subsidence.

PG&E's CAVA addresses actual or expected climatic impacts on the gas transmission system, with a focus on the 2050 decadal time period. The CAVA assessment on PG&E's Gas Transmission Assets considered impacts to utility planning, facilities maintenance and construction, and communications, to maintain safe, reliable, affordable and resilient operations.[5] The CAVA results do not explicitly consider how climate change will directly impact the likelihood of a LOC event. Instead, the CAVA climate risk findings consider generalized impacts from future climate hazards to gas transmission pipelines that could have significant consequences for customers, public safety, and the environment, with

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[5] PG&E's Climate Adaptation Vulnerability Assessment, Section 3.1.2.a Gas Transmission (to be Published May 15, 2024).

impacts ranging from interrupted service to gas leaks, pipeline ruptures and combustion.

TABLE 1-5
GAS TRANSMISSION CAVA CLIMATE RISK SCORES

Line No.	Climate Hazard	Adaptive Capacity	Climate Change Risk
1	Temperature	High	Low (off-ramped)
2	Flooding/Precipitation	Moderate	Moderate
3	Sea Level Rise	High	Low (off-ramped)
4	Wildfire	High	Low (off-ramped)
5	Drought-driven subsidence	High	Low (off-ramped)

The adaptive capacity of PG&E's gas transmission assets to future climate hazards were a key factor in determining the Company's climate risk rankings. Adaptive capacity was defined as the ability of an asset or system to moderate or eliminate identified climate vulnerabilities as assessed based on 2050 conditions and mitigate future impacts. This included any aspect of design, planning, operations, monitoring, emergency response capacities, and other PG&E capabilities. PG&E's CAVA (see Table 1-5 above) found that Gas Transmission current mitigations and controls result in high adaptive capacity to address climate risks associated with temperatures, sea level rise, wildfire, and drought-driven subsidence, and moderate adaptive capacity to address climate risks from flooding/precipitation.

7. Cross-Cutting Factors

A cross-cutting factor is a driver, component of a driver, or a consequence multiplier that impacts multiple risks. PG&E is presenting seven cross-cutting factors in the 2024 RAMP. The cross-cutting factors that impact the LOCTM risk are shown in Table 1-6 below.

TABLE 1-6
CROSS-CUTTING FACTOR SUMMARY

Line No.	Cross-Cutting Factor	Impacts Likelihood	Impacts Consequence
1	Climate Change	Yes*	No
2	Cyber Attack	No	No
3	Emergency Preparedness and Response	No	Yes*
4	Information Technology Asset Failure	No	No
5	Physical Attack	Yes	No
6	RIM	Yes	Yes
7	Seismic	Yes	Yes

Yes The cross-cutting factor has been quantified in the model.

Yes* The cross-cutting factor does influence the baseline risk but has not been quantified in the model, or the cross-cutting factor may influence the baseline risk but further study is needed.

No The cross-cutting factor does not meaningfully influence the baseline risk.

When analyzing the LOCTM risk, PG&E considered the cross-cutting factor Climate Change. Climate-related drivers are mainly captured under the WROF driver (landslides, erosion, subsidence, wildfire). In the context of Climate Change, the Gas Transmission risk team discussed the potential impact that wildfires could have on this risk and concluded that the impact would be small given that transmission pipeline assets are mostly underground. PG&E also evaluated the possible impacts of climate change resulting in increased subsidence. PG&E commissioned a study that looked at a critical area (Line 186) and concluded that existing pipeline assets are fit for service and able to operate under expected subsidence by 2060 even when using conservative estimates. Potential increases in corrosion rates due to sea level rise were also evaluated concluding that existing mitigation programs are adequate and able to address any additional Cathodic Protection (CP) needs that may arise. Even though climate change is not a significant risk driver for this risk during the 2024 RAMP period, PG&E does consider gas transmission pipeline impacted by climate change as one of its alternative mitigations (Section E.1).

A description of the cross-cutting factors and the mitigations and controls that PG&E is proposing to mitigate the cross-cutting factors is in Exhibit (PG&E-2), Chapter 3.

8. Consequences

The basis for measuring the consequences of this risk is: did a significant LOCTM event occur, and if so, (1) did the LOC result in a leak or (2) did the LOC result in a rupture, and if so, (3) was the leak or rupture caused by a seismic event.

The overall leak and rupture consequences of a LOCTM risk event occurring are:

- 61.7 percent of significant LOC events resulted in a rupture, contributing 99.4 percent of the overall risk; and
- 38.3 percent of significant LOC events resulted in a leak is, contributing 0.6 percent of the overall risk.

The modeled consequences of a LOCTM risk event occurring are:

- 60 percent of non-seismic significant LOC events result in a rupture, contributing 76.5 percent of the overall risk.
- 40 percent of non-seismic significant LOC events result in a leak, contributing 0.6 percent of the overall risk.
- 86 percent of seismic significant LOC events result in a rupture, contributing 22.9 percent of the overall risk; and
- 14 percent of seismic significant LOC events result in a leak, contributing 0.02 percent of the overall risk.

The consequences of this risk are measured in terms of safety, reliability, and financial impacts.

For safety consequences of rupture LOCs, PG&E continues to aggregate the potential safety impacts of a Transmission LOC from segment level granularity of the TIMP risk model. A methodology was developed to translate TIMP safety outputs (represented as IOC) into the safety units required for GRC modeling (represented as Serious Injury or Fatality (SIF)) by analyzing the historical relationship between IOCs and SIFs from previous LOC events. The safety consequences of leak LOCs are calculated based on the historical PHMSA incidents due to the lack of PG&E incidents with non-zero SIF. PG&E's reliability consequence profiles are different for ruptures and leaks. For ruptures, reliability consequences represent the expected number of impacted customers in the case of service being interrupted to the pipeline segment. The distributions leverage customer impact data from the TIMP model, however, these distributions have been modified to better represent both PG&E observed and potential reliability events.

Based on the model results, for ruptures, a 65.17 percent probability of a rupture leading to a reliability incident (customer outage) was calculated from PHMSA data 2010-June 2023, assuming those incidents with an estimated cost of operator's emergency response were incidents that lead to a reliability event.

For leaks, the reliability consequences were determined based on PG&E GQI Report data from 2010-2022. From this historical data, the number of customers out of service was fit to a lognormal distribution. A 41.18 percent probability of a leak leading to a reliability incident (customer outage) was also calculated from this data.

PG&E's financial consequences were estimated from the PHMSA financial data which captures costs associated with property damage and emergency response. Multiple probabilistic distributions were used to fit against the data and the one with the best fitting performance was selected. For rupture incidents occurring in HCAs, the Pareto power law distribution was tested to be the best fitting model, whereas for leak incidents, as well as rupture incidents occurring in the non-HCAs, the lognormal distribution performed best.

Table 1-7 below shows the consequences of the risk event. Model attributes are described in Exhibit (PG&E-2), Chapter 2.

TABLE 1-7
RISK EVENT CONSEQUENCES

					Natural Units Per Event			Monetized Levels of a Consequence Per Event (2023 $M/event)			CoRE (risk-adjusted 2023 $M)			Natural Units per Year			Expected Loss per Year (2023 $M/yr)			Risk Value (risk-adjusted 2023 $M/yr)		
Outcomes	CoRE	%Freq	%Risk	Freq	Safety EF/event	Gas Reliability #cust/event	Financial $M/event	Safety	Gas Reliability	Financial	Safety	Gas Reliability	Financial	Safety EF/yr	Gas Reliability #cust/yr	Financial $M/yr	Safety	Gas Reliability	Financial	Safety	Gas Reliability	Financial
Ruptures	68.3	57%	77%	2.08	0.71	3,820	3.0	10.8	6.0	3.0	48.9	8.9	10.6	1.47	7,963	6.15	22.45	12.50	6.15	101.85	18.51	22.09
Seismic - Rupture	247.0	5%	23%	0.17	2.53	5,995	8.3	38.5	9.4	8.3	211.9	16.2	19.0	0.44	1,033	1.44	6.63	1.62	1.44	36.52	2.78	3.27
Leaks	0.8	38%	1%	1.37	0.01	102	0.5	0.1	0.2	0.5	0.1	0.2	0.5	0.01	141	0.69	0.13	0.22	0.69	0.13	0.24	0.69
Seismic - Leak	1	1%	0%	0.03	0.01	137	0.7	0.1	0.2	0.7	0.1	0.2	0.7	0.00	4	0.02	0.00	0.01	0.02	0.00	0.01	0.02
Aggregated	50.9	100%	100%	3.66	0.52	2,498	2.3	8.0	3.9	2.3	37.9	5.9	7.1	1.92	9,141	8.30	29.22	14.35	8.30	138.51	21.54	26.07

a. Potential Environmental and Social Justice Consequences

PG&E selected LOCTM as an Environmental and Social Justice Pilot Study Plan (PSP) pilot risk for Action Items #1 and #6.[6] To address these Action Items, PG&E developed a methodology for determining the impact to Disadvantaged and Vulnerable Communities (DVCs, as defined in D.22-12-027) and used this methodology to calculate the consequences, mitigation benefits, and the total costs of mitigations associated with DVCs.

1) Methodology

LOCTM utilized a percentage-based approach to determine impacts of the risk to DVCs. To determine the percentage in the approach, DVCs were mapped in GIS and the amount of area impacted by the risk that was in a DVC was compared to the total area impacted. This resulting percentage was multiplied to the consequences of each tranche to determine the Likelihood of a Risk Event and Consequence of Risk Event of the impacts of the risk to the DVC. Mitigations with non-specific locations in a tranche were assumed to be partially applied to the DVC as well, thus the percentage from the tranche analysis was carried through the mitigation benefit, as well as the cost.

2) Tranches

For the LOCTM risk, the tranche analysis determined the following separation of DVC and non-DVC areas in each tranche. Table 1-7A below depicts tranches and associated DVC and non-DVC mileages plus percents.

[6] See Exhibit (PG&E-2), Chapter 7.

TABLE 1-7A
DVC BY TRANCHES

Line No.	Tranches	Non-DVC Mileage	DVC Mileage	Total Mileage	% DVC by Tranche
1	All Other Pipe and (IOC = 0 or leak mode on Non-HCA/MCA)	626.97	238.11	865.08	28%
2	All Other Pipe and (IOC > 0 & rupture mode on Non-HCA/MCA)	35.65	12.32	47.98	26%
3	All Other Pipe and HCA	412.66	196.44	609.11	32%
4	All Other Pipe and MCA	185.04	60.48	245.52	25%
5	Geohazard Pipe and (IOC = 0 or leak mode on Non-HCA/MCA)	605.32	254.64	859.96	30%
6	Geohazard Pipe and (IOC > 0 & rupture mode on Non-HCA/MCA)	21.59	6.95	28.55	24%
7	Geohazard Pipe and HCA	298.20	71.28	369.48	19%
8	Geohazard Pipe and MCA	91.15	43.42	134.57	32%
9	Potential IC Pipe and (IOC = 0 or leak mode on Non-HCA/MCA)	344.55	214.89	559.45	38%
10	Potential IC Pipe and (IOC > 0 & rupture mode on Non-HCA/MCA)	14.80	12.35	27.15	45%
11	Potential IC Pipe and HCA	127.63	75.22	202.85	37%
12	Potential IC Pipe and MCA	63.15	82.32	145.47	57%
13	Potential Manufacturing Defect Pipe and (IOC = 0 or leak mode on Non-HCA/MCA)	806.83	105.89	912.71	12%
14	Potential Manufacturing Defect Pipe and (IOC > 0 & rupture mode on Non-HCA/MCA)	27.21	9.60	36.80	26%
15	Potential Manufacturing Defect Pipe and HCA	136.54	61.83	198.37	31%
16	Potential Manufacturing Defect Pipe and MCA	124.88	32.05	156.94	20%
17	Potential SCC/SSWC Pipe and (IOC = 0 or leak mode on Non-HCA/MCA)	262.33	69.19	331.52	21%
18	Potential SCC/SSWC Pipe and (IOC > 0 & rupture mode on Non-HCA/MCA)	8.65	4.95	13.60	36%
19	Potential SCC/SSWC Pipe and HCA	39.32	11.97	51.29	23%
20	Potential SCC/SSWC Pipe and MCA	29.97	2.47	32.44	8%
21	Shallow/Exposed Pipe and (IOC = 0 or leak mode on Non-HCA/MCA)	303.62	101.09	404.72	25%
22	Shallow/Exposed Pipe and (IOC > 0 & rupture mode on Non-HCA/MCA)	12.21	5.33	17.54	30%
23	Shallow/Exposed Pipe and HCA	109.25	52.69	161.95	33%
24	Shallow/Exposed Pipe and MCA	67.76	26.42	94.18	28%
25	Grand Total	4,755.30	1,751.92	6,507.22	27%

Note: For additional details see Exhibit (PG&E-3), WP GO-LOCTM-19.

3) Consequences

Applying the percentage methodology described above to the Consequences of the risk results in the following risk scores. Table 1-7B below depicts consequences impacts to DVCs.

TABLE 1-7B
DVC CONSEQUENCES IMPACT

Risk Value

	Exposure (miles)	Safety (risk-adj. $M)	Gas Reliability (risk-adj. $M)	Financial (risk-adj. $M)	Total Risk (risk-adj. $M)
DVC	1,751.9	35.89	5.80	7.31	49.00
Non-DVC	4,755.3	104.09	15.92	19.03	139.05
Total	*6,507.2*	*140.0*	*21.7*	*26.3*	*188.0*
	(%)	(%)	(%)	(%)	(%)
DVC	26.9%	25.6%	26.7%	27.7%	26.1%
Non-DVC	73.1%	74.4%	73.3%	72.3%	73.9%

Natural Units

	Exposure (miles)	Safety (EF)	Gas Reliability (customers)	Financial ($M)
DVC	1,751.9	0.83	0.50	3.31
Non-DVC	4,755.3	2.04	1.27	9.00
Total	*6,507.2*	*2.9*	*1.8*	*12.3*
	(%)	(%)	(%)	(%)
DVC	26.9%	28.9%	28.3%	26.9%
Non-DVC	73.1%	71.1%	71.7%	73.1%

Note: For additional details see Exhibit (PG&E-3), WP GO-LOCTM-19.

4) Mitigation Benefits

Continuing with the percentage approach, the following risk reductions are expected to be relevant to DVCs. Table 1-7C below depicts risk reductions as is portrayed for other mitigations with percentage applied for DVC benefit.

TABLE 1-7C
DVC BENEFIT RISK REDUCTIONS AND SPEND %

	Risk Reduction				Spend			
	($M, risk adj.)		(%)		($M, NPV)		(%)	
Program	*DVC*	*Non-DVC*	*DVC*	*Non-DVC*	*DVC*	*Non-DVC*	*DVC*	*Non-DVC*
Geo-Hazard Threat Identification and Mitigation	0.02	0.1	25%	75%	8.1	18.2	31%	69%
LNG/CNG to Support Strength Testing	1.2	3.2	27%	73%	7.2	19.5	27%	73%
Earthquake Fault Crossings	0.3	1.0	20%	80%	14.5	36.1	29%	71%
In-Line Inspection	1,687.3	4,177.6	29%	71%	323.3	808.5	29%	71%
Gas Gathering Divestiture	0.6	1.3	32%	68%	5.5	15.5	26%	74%
Shallow and Exposed Pipe (Including Water and Levee Crossings) - Control	0.004	0.008	32%	68%	0.9	2.4	28%	72%
Pipeline Safety and Reliability	0.2	0.6	24%	76%	8.3	34.5	19%	81%
Locate and Mark - Transmission	68.9	178.8	28%	72%	0.6	1.6	27%	73%
Locate and Mark - Transmission Standby	131.5	341.0	28%	72%	4.3	11.7	27%	73%
Public Awareness	42.8	110.9	28%	72%	1.4	3.8	27%	73%
Required Pipeline Patrol Program	37.8	98.2	28%	72%	5.6	15.3	27%	73%
PM Gas Pipeline Valves Program	0.2	0.4	28%	72%	1.1	3.1	27%	73%
CM Gas Pipeline Valves Program	24.0	65.0	27%	73%	0.5	1.4	27%	73%
Pipeline Marker Maintenance	25.8	66.8	28%	72%	0.5	1.3	27%	73%
Vegetation Management	0.1	0.3	26%	74%	1.2	3.2	27%	73%
Vegetation Manage Project	11.2	32.6	26%	74%	3.8	10.2	27%	73%
Encroachments	3.0	8.1	27%	73%	1.5	4.1	27%	73%
Cathodic Protection	509.3	1,259.8	29%	71%	9.9	26.9	27%	73%
Transmission Leak Management	43.1	110.5	28%	72%	5.5	15.0	27%	73%
Direct Assessment	1.4	3.4	30%	70%	70.0	160.7	30%	70%
Valve Safety and Reliability	214.8	608.9	26%	74%	25.8	70.1	27%	73%
TIMP Strength Testing	0.4	0.9	29%	71%	13.6	34.3	28%	72%
Pipe Investigations and Field Engineering	21.8	55.1	28%	72%	2.8	7.6	27%	73%
Class Location Change	0.1	0.1	34%	66%	25.3	51.5	33%	67%
Gas Holder Maintenance	0.01	0.02	26%	74%	0.1	0.2	27%	73%
Internal Corrosion Program	0.3	0.6	29%	71%	3.7	10.1	27%	73%
Electrical Interference Program	29.0	71.5	29%	71%	8.1	22.0	27%	73%
Atmospheric Corrosion Program	4.6	11.4	29%	71%	3.4	9.1	27%	73%
Transmission Corrosion Control Program	4.9	12.0	29%	71%	20.3	55.0	27%	73%
Vintage Pipe Replacement	1.6	4.6	25%	75%	2.0	5.9	25%	75%
Shallow and Exposed Pipe (Including Water and Levee Crossings) - Mitigation	0.2	0.5	30%	70%	7.6	19.2	28%	72%
Non-TIMP Strength Testing	3.5	8.8	28%	72%	80.0	231.2	26%	74%
Valve Automation	8.3	23.3	26%	74%	19.9	49.2	29%	71%
Total	**2,877.8**	7,257.3	28.4%	71.6%	**686.3**	1758.2	28.1%	71.9%

Note: For additional details see Exhibit (PG&E-3), WP GO-LOCTM-19.

5) Cost Comparison

Using the tranche percentage approach, PG&E expects $686.3 million to be spent on mitigations reducing risk in DVCs relative to $2,877.8 million total spend for risk reduction (refer to Table 1-7C above).

C. 2023-2026 Control and Mitigation Plan

Tables 1-8 and 1-9 list the controls and mitigations PG&E included in its 2020 RAMP, 2023 GRC and 2024 RAMP (2024-2026 and 2027-2030). The tables provide a view as to those controls and mitigations that are on-going, those that are no longer in place, and new mitigations. In the following sections, PG&E describes the controls and mitigations in place in the 2023-2026 period and then discusses new mitigations and/or significant changes to mitigations and/or controls during the 2027-2030 period.

TABLE 1-8
CONTROLS SUMMARY

Line No.	Control Number and Name[(a)]	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2023-2026)	2024 RAMP (2027-2030)
1	C1 – Corrosion Control	X	Split into LOCTM-C019, LOCTM-C032, LOCTM-C033, LOCTM-C034 & LOCTM-C035		
2	C2 – Direct Assessments (DA)	X	Becomes LOCTM-C022		
3	C3 – TIMP Pressure Tests	X	Becomes LOCTM-C026		
4	C4 – Leak Survey	X	Becomes LOCTM-C020		
5	C5 – Locate and Mark	X	Split into LOCTM-C009, LOCTM-C010 & LOCTM-C012		
6	C6 – Patrols	X	Becomes LOCTM-C012		
7	C7 – Public Awareness	X	Becomes LOCTM-C011		
8	C8 – ILIs – Re-inspections	X	Becomes LOCTM-C005		
9	C9 – Pipe Replacement Program	X	Split into LOCTM-C008, LOCTM-C018, LOCTM-C024, LOCTM-C025 & LOCTM-C026		
Line No.	Control Number and Name[(a)]	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2023-2026)	2024 RAMP (2027-2030)

TABLE 1-8
CONTROLS SUMMARY
(CONTINUED)

Line No.	Control Number and Name[(a)]	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2023-2026)	2024 RAMP (2027-2030)
10	C10 – Geohazard Control Program	X	Split into LOCTM-C001, LOCTM-C004, LOCTM-C007 & LOCTM-M002		
11	C11 – Other Operations and Maintenance	X	Split into LOCTM-C006, LOCTM-C008, LOCTM-C013, LOCTM-C014, LOCTM-C015, LOCTM-C016, LOCTM-C017, LOCTM-C021, LOCTM-C023, LOCTM-C027, LOCTM-C030 & LOCTM-C036		
12	LOCTM-C001 – Geo-Hazard Threat Identification and Mitigation		X	X	X
13	LOCTM-C002 – Liquefied Natural Gas (LNG)/Compressed Natural Gas (CNG) to Support Strength Testing		X	X	X
14	LOCTM-C003 – Gas Research and Development (R&D) and Deployment		X		

TABLE 1-8
CONTROLS SUMMARY
(CONTINUED)

Line No.	Control Number and Name[a]	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2023-2026)	2024 RAMP (2027-2030)
15	LOCTM-C004 – Earthquake Fault Crossings		X	X	X
16	LOCTM-C005 – In-Line Inspection		X	X	X
17	LOCTM-C006 – Gas Gathering Divestiture		X	X	X
18	LOCTM-C007 – Shallow and Exposed Pipe (Including Water and Levee Crossings) – Control		X	X	X
19	LOCTM-C008 – Pipeline Safety and Reliability		X	X	X
20	LOCTM-C009 – Locate and Mark – Transmission		X	X	X
21	LOCTM-C010 – Locate and Mark - Transmission Standby		X	X	X
22	LOCTM-C011 – Public Awareness		X	X	X
23	LOCTM-C012 – Required Pipeline Patrol Program		X	X	X
24	LOCTM-C013 – Preventative Maintenance (PM) Gas Pipeline Valves Program		X	X	X
25	LOCTM-C014 – Corrective Maintenance (CM) Gas Pipeline Valves Program		X	X	X
26	LOCTM-C015 – Pipeline Marker Maintenance		X	X	X
27	LOCTM-C016 – Vegetation Management		X	X	X
28	LOCTM-C017 – Vegetation Manage Project		X	X	X

TABLE 1-8
CONTROLS SUMMARY
(CONTINUED)

Line No.	Control Number and Name[a]	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2023-2026)	2024 RAMP (2027-2030)
29	LOCTM-C018 – Encroachments		X	X	X
30	LOCTM-C019 – Cathodic Protection		X	X	X
31	LOCTM-C020 – Transmission Leak Management		X	X	X
32	LOCTM-C021 – Gas Transmission and Storage (GT&S) Operations		X		
33	LOCTM-C022 – Direct Assessment		X	X	X
34	LOCTM-C023 – Operate Transmission Pipelines		X		
35	LOCTM-C024 – Valve Safety and Reliability		X	X	X
36	LOCTM-C025 – Class Location Change		X	X	X
37	LOCTM-C026 – TIMP Strength Testing		X	X	X
38	LOCTM-C027 – Pipe Investigations and Field Engineering		X	X	X
39	LOCTM-C028 – Production Mapping Transmission		X		
40	LOCTM-C029 – Risk Analysis		X		
41	LOCTM-C030 – Root Cause Analysis		X	X	X
42	LOCTM-C031 – Gas Holder Maintenance		X	X	X
43	LOCTM-C032 – Internal Corrosion Program		X	X	X
44	LOCTM-C033 – Electrical Interference Program		X	X	X
45	LOCTM-C034 – Atmospheric Corrosion (AC) Program		X	X	X
46	LOCTM-C035 – Transmission Corrosion Control Program		X	X	X
47	LOCTM-C037 – Stan-Pac Capital		X	X	X
48	LOCTM-C038 – Stan-Pac Expense		X	X	X

(a) Controls included in the 2020 RAMP were not labeled with Risk ID (LOCTM), distinguishing between Control Numbers used in the 2020 RAMP Report and Control Numbers used in the 2023 GRC and 2024 RAMP.

TABLE 1-9
MITIGATIONS SUMMARY

Line No.	Mitigation Name and Number[a]	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2023-2026)	2024 RAMP (2027-2030)
1	M1 – ILI Upgrades	X	Becomes LOCTM-M005		
2	M2 – Strength Testing	X	Becomes LOCTM-M003		
3	M3 – Vintage Pipe Replacement	X	Becomes LOCTM-M001		
4	M4 – Valve Automation	X	Becomes LOCTM-M004		
5	M5 – Shallow Pipe	X	Becomes LOCTM-M002		
6	M6 – Exposed Pipe	X	Becomes LOCTM-M002		
7	LOCTM-M001 – Vintage Pipe Replacement		X	X	X
8	LOCTM-M002 – Shallow and Exposed Pipe (Including Water and Levee Crossings) - Mitigation		X	X	X
9	LOCTM-M003 – Non-TIMP Strength Testing		X	X	X
10	LOCTM-M004 – Valve Automation		X	X	X
11	LOCTM-M005 – Traditional ILI Upgrades		X		

(a) Mitigations included in the 2020 RAMP were not labeled with Risk ID (LOCTM), distinguishing between Mitigation Numbers used in the 2020 RAMP Report and Mitigation Numbers used in the 2023 GRC and 2024 RAMP.

1. Controls

In the 2020 RAMP Report, PG&E identified 11 controls. For the 2023 GRC, PG&E identified 37 controls for LOCTM. After filing the 2020 RAMP Report, Gas Operations reviewed every program in its portfolio and mapped each program as a risk mitigation or control, if it applied to this risk as part of our risk management strategy. PG&E determined that certain programs did not apply, such as customer-requested work or emergency response. Based on this detailed evaluation, Gas Operations identified several more programs that aligned to the risk management strategy and thus are included as controls for this risk.

LOCTM-C001 – Geo-Hazard Threat Identification and Mitigation: This control addresses the specific threat of damage to a pipeline from land movement strains at known earthquake faults due to seismic events and other geohazards.

LOCTM-C002 – LNG/CNG to Support Strength Testing: This control addresses corrective and preventive maintenance on LNG/CNG emission reduction equipment, trailers, vaporizers, some capital repair components, etc. whose primary design purpose is to support customer loads during capacity reductions.

LOCTM-C003 – Gas R&D and Deployment: This control addresses detection, developing, testing, and introducing new methods and technologies into PG&E's Gas Transmission operations to improve gas safety, reliability, and efficiency.

LOCTM-C004 – Earthquake Fault Crossings: This control addresses Fault Crossing Program studies: (1) conducting studies of locations where gas transmission pipelines cross known earthquake fault lines and (2) long-term ongoing monitoring of fault creep of mitigated crossings.

LOCTM-C005 – In-Line Inspection: This control addresses traditional ILI cleaning and inspection, and Non-Traditional ILI runs on gas transmission pipelines. This also includes ILI direct examination digs and repairs made as a result of the ILI results, repairs from ILI required as a result of an ILI assessment such as pipe replacements (e.g., >50 feet (ft.), coating >100 ft.). ILI Upgrade Projects were moved to this control from mitigation LOCTM-M005 for 2024 RAMP, where making one-time pipeline modifications allows the smart pig to run unimpeded through the pipeline (e.g., removing elbows and other physical constraints and installing valves, pig launchers and receivers).

LOCTM-C006 – Gas Gathering Divestiture: This control addresses work associated with the sale and/or retirement of pipe on the gas gathering system.

LOCTM-C007 – Shallow and Exposed Pipe (Including Water and Levee Crossings) – Control: This control addresses assessing shallow and exposed pipe as required (e.g., protection of the pipeline by installing additional cover), and assessment and monitoring of water and levee crossings.

LOCTM-C008 – Pipeline Safety and Reliability: This control addresses replacement of pipe > 50 feet in length where there are pipeline safety or reliability issues, not captured by other Maintenance Activity Types (MAT) (e.g., leaks, dig-ins, corrosion Integrity Issues, overbuilds/encroachments, or retirements/deactivations). This also includes pipeline repairs due to leaks, corrosion, weld, or damage, etc. where a non-capital asset was installed (clamp, sleeve, etc.), and/or pipe <50 ft. was cut-out and replaced (e.g., third party damage or dig-ins, gas gathering sales, etc.).

LOCTM-C009 – Locate and Mark – Transmission: This control addresses third party damage by the locate and mark of underground Gas Transmission facilities per USA (Underground Service Alert) requests.

LOCTM-C010 – Locate and Mark – Transmission Standby: This control addresses PG&E or third-party standby work of underground Gas Transmission facilities (e.g., standby puts a person onsite to direct the excavator and visually monitor excavation work).

LOCTM-C011 – Public Awareness: This control addresses work that supports the PAP requirements based on the American Petroleum Institute's Recommended Practice 1162 (RP1162), 1st Edition, December 2003, that requires pipeline operators to develop and implement gas safety and damage prevention focused on public education programs that address key stakeholder audiences including the affected public, emergency officials, public officials, and excavators.

LOCTM-C012 – Required Pipeline Patrol Program: This control addresses work associated with compliance for ground Pipeline Patrols and includes work for ground patrol within no-fly zones and/or ground patrol assessments in response to aerial patrol findings.

LOCTM-C013 – Preventive Maintenance (PM) Gas Pipeline Valves Program: This control addresses scheduled inspections of Transmission manual and automated valves, automated actuators, outside of stations. This also includes maintenance performed on fire valves (inlet/outlet valves) on distribution regulator stations.

LOCTM-C014 – Corrective Maintenance (CM) Gas Pipeline Valves Program: This control addresses repairs or replacement (up to 2”) of Transmission pipeline manual and automated valves, automated actuators, outside of stations, and includes corrective maintenance performed on fire valves (inlet/outlet valves) on distribution regulator stations.

LOCTM-C015 – Pipeline Marker Maintenance: This control addresses installing, replacing, and maintaining pipeline markers and indicators on transmission lines, includes warning signs where the pipeline crosses a waterway.

LOCTM-C016 – Vegetation Management: This control addresses routine weed abatement in and around gas transmission stations.

LOCTM-C017 – Vegetation Manage Project: This control addresses Vegetation Management Operations work that supports the safety and integrity of gas pipelines by annually inspecting and physically controlling and maintaining vegetation, and by keeping exposed pipelines clear of potential hazards. It also includes foot patrols and inspections of 100 percent of the pipeline miles for vegetation encroachments, and a bi-annual patrol of areas where fast growing vegetation has been identified.

LOCTM-C018 – Encroachments: This control addresses mitigation of pipeline encroachments which covers only non-items impacting comparability (IIC) charges for: structures in right of way (ROW), pipeline access roads, ROW clean-up and access issues not related to vegetation management.

LOCTM-C019 – Cathodic Protection (CP): This control addresses activities that ensure and restore adequate CP correct any deficiencies such as:

- Routine, corrective and annual monitoring activities (e.g., pipe-to-soil reads, casing-to-soil reads, repairing existing anodes or rectifiers, annual rectifier maintenance, etc.)
- Installing insulators, bonds, recoating less than 100 ft. of buried piping, and implementing the 850-Off criterion.
- Assessment and installment of test stations to determine adequate CP.
- Conducting Close Interval Survey to evaluate the health of the corrosion control system where locations of possible active EC are identified and analyzed through excavation and/or direct examination.

LOCTM-C020 – Transmission Leak Management: This control addresses work associated with:

- Leak repairs at pipeline stations and non-dig-in leaks on any transmission pipelines and associated appurtenances (flanges, valves, etc.). This also includes leaks checks according to leak grade.
- Foot and mobile surveys of transmission pipelines, including on waterways.
- Aerial leak surveys of transmission pipelines.

LOCTM C021 – GT&S Operations: This control addresses work activities that involve operation and control of the GT&S system in order to support customers in using the system, and plan for capacity and operations on a daily and longer-term basis. (e.g., plan and conduct engineering analysis for: daily operations and to determine capacity available for marketing; or long-term backbone, storage, and local transmission capacity, facility requirements, and operations).

LOCTM-C022 – Direct Assessment (DA): This control addresses activities associated with DA and Examination methods:

- Repairs or replacements related to Internal Corrosion Direct Assessment (ICDA), External Corrosion Direct Assessment (ECDA), and Stress Corrosion Cracking Direct Assessment (SCCDA) Phase 3 (e.g., pipe replacements >50 f.t, coating >100 ft., etc.).

- Phase 1 (Pre-Assessment), Phase 2 (Indirect Inspection Testing), and Phase 4 (Post-Assessment) activities for ICDA, ECDA, and SCCDA.
- Direct Examination as an assessment method (e.g., excavation, examination, repair, and continual evaluation). This also includes repairs as a result of Direct Examination integrity assessments.

LOCTM-C023 – Operate Transmission Pipelines: This control addresses work activities associated with operating the transmission pipeline system (e.g., operating valves as required, taking readings from odorometers and other equipment; calibrating test gauges and portable pressure recorders; monitoring pressures; removing pipeline liquids; and collecting charts)

LOCTM-C024 – Valve Safety and Reliability: This control addresses replacements of:

- Inoperable or hard-to-operate valves that are: >2" in diameter, <2" in diameter and non-corrective maintenance valve repairs (e.g., replacement of operator extension, gearbox, etc.) regardless of valve size.
- Valves that are leaking, deactivated to be removed, and removed or replacement of other reliability valves; and valves replaced for class location changes.

LOCTM-C025 – Class Location Change: This control addresses work that validates pipelines are operating within the appropriate class as determined by population density and includes:

Routine Class Location studies, including orthographically-corrected aerial photography, occupancy field verification, creation of a digitized structures layer, and annual class analysis.

Replacement of pipe due to class location change as identified by the Class Location Study Program.

Hydrotesting pipe where hydrotesting is the appropriate mitigation when the Class location study program has identified a need to mitigate due to a class location change.

LOCTM-C026 – TIMP Strength Testing: This control addresses activities that validate the integrity of pipe located in HCAs, Class 3 and 4, non-HCA, and potentially new MCAs and includes:

- Pipe replacements for the purpose of assessing pipeline identified by TIMP to be in compliance with 49 CFR Part 192, Subpart O in lieu of hydrostatic testing. This also includes pipe replacements that are >50 ft. in length and are being replaced in lieu of hydrostatic testing to address an integrity threat, such as the manufacturing threat.
- Replacements on pipe segments less than 50 ft. due to integrity management threats.
- Hydrostatic tests conducted for the purpose of assessing pipeline identified by TIMP to be in compliance with 49 CFR Part 192, Subpart O which involves three efforts: (1) review and validation of records to prove a pipeline has had a prior hydrostatic test performed, (2) pipeline replacement where necessary to prepare a pipeline for testing, and (3) filling the inside of the pipeline with water and raising the pressure to a predetermined value and holding it for a period of time.

LOCTM-C027 – Pipe Investigations and Field Engineering: This control addresses Pipeline Other and Engineering support work done throughout the system (e.g., scoping studies and field investigations such as Maximum Allowable Operating Pressure (MAOP) discoveries, potential mechanical damage investigations, anomaly investigations, etc.).

LOCTM-C028 – Production Mapping Transmission: This control addresses work associated with gas transmission asset information in our systems of record (e.g., GT – GIS, SAP; Electronic Compliance Tracking System/Documentum for storage of electronic documents; Map Correction CAPs; updates to Operating Maps/Operating Diagrams (OM/OD); and processing of Request of Work for Asset Registry updates).

LOCTM-C029 – Risk Analysis: This control addresses:

- All work and services associated with supporting the transmission Integrity Management program (includes overhead costs and any services and products not specific to any other MAT); and

- Semi-annual leak surveys conducted on Class 3/4 non-HCA pipeline operating under 30 percent Specified Minimum Yield Strength, in accordance with 49 CFR § 192.935 (d)(3).

LOCTM-C030 – Root Cause Analysis (Foundational): Refer to Section C.3 Foundational Activities for description.

LOCTM-C031 – Gas Holder Maintenance: This control addresses preventive and corrective maintenance on Gas Transmission Holders and associated equipment.

LOCTM-C032 – Internal Corrosion Program: This control addresses monitoring and mitigation efforts required to control the adverse effects of IC into PG&E’s gas system through storage or gas gathering facilities and includes:

- Routine monitoring for IC includes inline cleaning, testing internal probes/coupons, monitoring drips, and performing liquid analyses. This also includes IC investigations conducted by Corrosion Engineering (not ICDA).

LOCTM-C033 – Electrical Interference Program: This control addresses mitigation activities where pipelines run in proximity to electric transmission lines which may result in the induction of Alternating Current to the pipe, as well as fault strikes (e.g., relocating the electric facility or gas piping). A secondary purpose is to address minimizing the detrimental effects of Direct Current Interference from foreign CP systems, mass transit systems, and other sources (e.g., upgrading rectifiers, installing new impressed current CP systems).

LOCTM-C034 – Atmospheric Corrosion (AC) Program: This control addresses AC mitigation activities:

- AC inspections which consist of two components: an initial survey and a follow up investigation when potential AC is indicated. If the remediation is needed as a result, to better address the AC, recoating the affected piping and conducting pipeline repairs can occur.

LOCTM-C035 – Transmission Corrosion Control Program: This foundational control addresses mitigations due to corrosion caused by a metallic or electrolytic contact between these two structures, and this includes activities such as:

- Coatings research, data/program management, field support, and remote monitoring unit licenses.
- Specialized testing required to monitor casings without test stations, leads, vents, or other facilities required to take casing-to-soil readings.
- Removing segments of casing, replacing link seals and insulation spacers, flushing and draining casings, repairing coatings, and gelling the casing after site restoration.

LOCTM-C037 – Stan-Pac Capital (Foundational): Refer to Section C.3 Foundational Activities for description.

LOCTM-C038 – Stan-Pac Expense (Foundational): Refer to Section C.3 Foundational Activities for description.

2. Mitigations

- **LOCTM-M001 – Vintage Pipe Replacement:** This mitigation addresses replacement of pipe segments containing vintage fabrication and construction threats that are subject to a high risk of land movement and are in proximity to population.
- **LOCTM-M002 – Shallow and Exposed Pipe (Including Water and Levee Crossings) – Mitigation:** This mitigation identifies, prioritizes, and mitigates locations where pipeline has insufficient cover, is vulnerable to exposure from third parties, or has become exposed due to natural forces. PG&E modified its portfolio of mitigations since filing the 2020 RAMP Report by incorporating "Water and Levee Crossings" into mitigation LOCTM-M002. This was added because it is part of the overall program work for the Shallow and Exposed Pipe (including Water and Levee Crossings)" Program. All three mitigations address similar risks and as such should be considered to work together for this risk reduction and are similarly prioritized within this family of work.
- **LOCTM-M003 – Non-TIMP Strength Testing:** This mitigation addresses strength tests pipe for several reasons, including to initially establish or reconfirm a Maximum Allowable Operating Pressure, when there is a Class Location change, as an integrity assessment to meet

regulatory requirements and to fulfill PG&E's obligation to the National Transportation Safety Board Safety Recommendation P-10-4, Public Utilities Code (Pub. Util. Code) 958 and 49 CFR § 192.624.

- **LOCTM-M004 – Valve Automation:** This mitigation addresses installation of automated isolation valves on pipelines in heavily-populated areas to enhance emergency response and to potentially reduce danger to emergency personnel and the public in the event of a pipeline rupture.
- **LOCTM-M005 – Traditional ILI Upgrades:** This mitigation addresses making one-time modifications to the pipeline to be able to run a Traditional ILI tool unimpeded through the pipeline. PG&E modified its portfolio of mitigations since the 2023 GRC by removing LOCTM-M005 Traditional ILI Upgrades as a mitigation and incorporating this ILI upgrades program into the LOCTM-C005 – ILI Control.

TABLE 1-10
2024-2026 PLANNED MITIGATIONS

			Planned Units of Work				
Line No.	Mitigation ID	Mitigation Name	Unit of Measurement[(a)]	2024	2025	2026	Total
1	LOCTM-M001	Vintage Pipe Replacement	Miles	–	0.99	0.73	1.72
2	LOCTM-M002	Shallow and Exposed Pipe (Including Water and Levee Crossings) Mitigation	Projects	1	1	2	4
3	LOCTM-M003	Non-TIMP Strength Testing	Miles	19.2	23.8	30.1	73.0
4	LOCTM-M004	Valve Automation	Valves	8	11	14	33

(a) The units of work are presented as used in the RAMP model because the model requires that units of work are standardized. These may differ in some instances from "rate case" units – the units referred to in PG&E's GRC or other proceedings.

Note: For additional details see Exhibit (PG&E-3), WP GO-LOCTM-F.

Table 1-10 above depicts the planned units of work for 2024-2026 mitigations. Tables 1-11 and 1-12 below show the cost estimates for the mitigation work planned for the 2024-2026 period.

TABLE 1-11
MITIGATION COST ESTIMATES
2024-2026 EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Mitigation ID	Mitigation Name	2024	2025	2026	Total
1	LOCTM-M003	Non-TIMP Strength Testing	$13,446	$13,177	$12,913	$39,536
2		Total	$13,446	$13,177	$12,913	$39,536

Notes: For additional details see Exhibit (PG&E-3), WP GO-LOCTM-F.
The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

TABLE 1-12
MITIGATION COST ESTIMATES
2024-2026 CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Mitigation ID	Mitigation Name	2024	2025	2026	Total
1	LOCTM-M001	Vintage Pipe Replacement	$1,965	$1,965	$1,965	$5,895
2	LOCTM-M002	Shallow and Exposed Pipe (Including Water and Levee Crossings) Mitigation	5,375	5,977	6,673	18,025
3	LOCTM-M003	Non-TIMP Strength Testing	67,654	64,435	68,944	201,033
4	LOCTM-M004	Valve Automation	12,100	14,451	17,166	43,717
5		Total	$87,094	$86,829	$94,748	$268,670

Notes: For additional details see Exhibit (PG&E-3), WP GO-LOCTM-F.
The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

3. Foundational Activities

As discussed in Exhibit (PG&E-2), Chapter 2, foundational activities are programs that enable two or more control or mitigation programs but do not directly reduce the consequences or the likelihood of risk events. Table 1-13 describes foundational activities that meet this definition and includes (1) information on the control or mitigation programs enabled and (2) the foundational activity program costs on a Net Present Value (NPV) basis that are included in CBR calculations for enabled control or mitigation programs.

LOCTM-C030 – Root Cause Analysis: This control addresses Integrity Management failures, incidents and leak investigations (i.e., engineering lab analysis).

LOCTM-C037 – Stan-Pac Capital: This control addresses improving the safety and reliability of the Stan Pac transmission pipeline system (i.e., replacing high risk, high consequence pipeline segments and pressure regulating facilities, new valves and catholic protection).

LOCTM-C038 – Stan-Pac Expense: This control Addresses maintenance, upkeep and repairs required to keep the Stan Pac transmission pipeline system operational.

TABLE 1-13
2027-2030 FOUNDATIONAL ACTIVITIES
(MILLIONS OF DOLLARS)

Line No.	Foundational Activity ID	Foundational Activity Name	Foundational Activity Description	Enabled Control and Mitigation IDs [(a)]	Net Present Value (NPV)[(b)]
1	LOCTM-C030	Root Cause Analysis	See description above	LOCTM-C005, LOCTM-C026, LOCTM-C027, LOCTM-C032, LOCTM-C035, LOCTM-M003	$3.04
2	LOCTM-C037	Stan-Pac Capital	See description above	LOCTM-C005, LOCTM-C008, LOCTM-C019, LOCTM-C024, LOCTM-C026, LOCTM-C027, LOCTM-C033, LOCTM-C035, LOCTM-M001, LOCTM-M002, LOCTM-M003	$11.36
3	LOCTM-C038	Stan-Pac Expense	See description above	LOCTM-C005, LOCTM-C008, LOCTM-C012, LOCTM-C013, LOCTM-C014, LOCTM-C015, LOCTM-C016, LRGOP-C011, LOCTM-C019, LOCTM-C020, LOCTM-C022, LOCTM-C024, LOCTM-C031, LOCTM-C033, LOCTM-C034, LOCTM-M002	$5.82
4		Total	–	–	$20.21

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

(b) NPV uses a base year of 2023.

Notes: For additional details see Exhibit (PG&E-3), WP GO-LOCTM-F.

The cost estimates in this table are generally based on PG&E’s 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

D. 2027-2030 Proposed Control and Mitigation Plan

1. Changes to Controls

There are 32 control programs—including three foundational activities—that continue through the years 2027 through 2030. Please see Table 1-8 in section C above for a complete list.

Table 1-14 below shows the cost estimates, risk reduction, and CBRs for the 29 non-foundational control programs planned for the 2027-2030 period.

TABLE 1-14
CONTROLS COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[b]			
Line No.	Control ID [a]	Control Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[c] [C]/([A]+[B])
1	LOCTM-C001	Geo-Hazard Threat Identification and Mitigation	$7,207	$7,326	$7,455	$7,585	$26.2	–	$0.1	<0.1
2	LOCTM-C002	LNG/CNG to Support Strength Testing	7,883	7,935	7,997	8,060	26.7	–	$4.4	0.2
3	LOCTM-C004	Earthquake Fault Crossings	13,005	13,344	13,705	14,066	50.6	–	$1.3	<0.1
4	LOCTM-C005	In-Line Inspection	334,108	336,376	339,033	341,745	1,131.7	13.2	$5,864.9	5.1
5	LOCTM-C006	Gas Gathering Divestiture	5,339	5,488	5,647	5,805	21.0	–	$1.9	0.1
6	LOCTM-C007	Shallow and Exposed Pipe (Including Water and Levee Crossings) - Control	1,222	1,197	1,173	1,150	3.3	–	$0.0	<0.1
7	LOCTM-C008	Pipeline Safety and Reliability	41,875	42,882	43,958	45,035	42.8	0.4	$0.8	<0.1
8	LOCTM-C009	Locate and Mark - Transmission	827	810	794	778	2.2	–	$247.8	111.5
9	LOCTM-C010	Locate and Mark - Transmission Standby	5,949	5,830	5,714	5,599	16.0	–	$472.5	29.5
10	LOCTM-C011	Public Awareness	1,953	1,914	1,875	1,838	5.2	–	$153.7	29.3
11	LOCTM-C012	Required Pipeline Patrol Program	7,776	7,620	7,468	7,318	20.9	0.1	$135.9	6.5
12	LOCTM-C013	PM Gas Pipeline Valves Program	1,556	1,525	1,494	1,465	4.2	0.0	$0.6	0.1
13	LOCTM-C014	CM Gas Pipeline Valves Program	711	697	683	669	1.9	0.0	$89.0	46.4
14	LOCTM-C015	Pipeline Marker Maintenance	657	643	631	618	1.8	0.0	$92.6	52.3
15	LOCTM-C016, LRGOP-C011	Vegetation Management[c]	1,640	1,608	1,575	1,544	4.4	0.0	$12.5	2.8
16	LOCTM C017	Vegetation Manage Project	5,205	5,101	4,999	4,899	14.0	–	$43.9	3.1

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[b]			
Line No.	Control ID [a]	Control Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[c] [C]/([A]+[B])
17	LOCTM C018	Encroachments	2,077	2,036	1,995	1,955	5.6	–	$11.1	2.0
18	LOCTM C019	Cathodic Protection	10,964	11,027	11,102	11,179	36.8	0.4	$1,769.1	47.6

TABLE 1-14
CONTROLS COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030
(CONTINUED)

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[b]			
Line No.	Control ID [a]	Control Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[c] [C]/([A]+[B])
19	LOCTM C020	Transmission Leak Management	$7,655	$7,501	$7,351	$7,204	$20.6	$0.1	$100.6	4.9
20	LOCTM-C022	Direct Assessment	84,277	82,752	81,266	79,811	230.7	0.8	$4.8	<0.1
21	LOCTM-C024	Valve Safety and Reliability	24,709	25,345	26,023	26,702	95.9	0.9	$823.7	8.5
22	LOCTM-C025	Class Location Change	19,951	20,438	20,959	21,479	76.8	–	$0.2	<0.1
23	LOCTM-C026	TIMP Strength Testing	14,218	14,304	14,406	14,510	47.9	0.4	$1.2	<0.1
24	LOCTM-C027	Pipe Investigations and Field Engineering	3,849	3,772	3,697	3,623	10.3	0.1	$76.8	7.4
25	LOCTM-C031	Gas Holder Maintenance	122	119	117	115	0.3	0.0	$0.0	0.1
26	LOCTM-C032	Internal Corrosion Program	4,384	4,374	4,369	4,365	13.8	0.0	$0.9	0.1
27	LOCTM-C033	Electrical Interference Program	8,098	8,254	8,423	8,592	30.1	0.3	$100.6	3.3
28	LOCTM-C034	Atmospheric Corrosion Program	4,374	4,314	4,257	4,201	12.5	0.0	$16.0	1.3
29	LOCTM-C035	Transmission Corrosion Control Program	20,567	20,924	21,311	21,700	75.3	0.6	$16.9	0.2
30		Total	$642,156	$645,457	$649,478	$653,611	–	–	–	–

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

(b) NPV uses a base year of 2023.

(c) CBR calculations include allocated Foundational Activity Program costs.

Notes: For additional details see Exhibit (PG&E-3), WP GO-LOCTM-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

2. Changes to Mitigations

There are four mitigation programs described above that continue through the years 2027 through 2030 (refer to section C, Table 1-9). The amount of work PG&E plans to complete is shown in Table 1-15 below.

TABLE 1-15
2027-2030 PLANNED MITIGATIONS

Line No.	Mitigation ID	Mitigation Name	Unit of Measurement [(a)]	Planned Units of Work 2027	2028	2029	2030	Total
1	LOCTM-M001	Vintage Pipe Replacement	Miles	2.9	1.3	1.3	1.3	6.9
2	LOCTM-M002	Shallow and Exposed Pipe (Including Water and Levee Crossings) Mitigation	Projects	2	2	2	2	8
3	LOCTM-M003	Non-TIMP Strength Testing	Miles	31.2	32.6	34.0	35.5	133
4	LOCTM-M004	Valve Automation	Valves	15	15	16	17	63

(a) The units of work are presented as used in the RAMP model because the model requires that units of work are standardized. These may differ in some instances from “rate case” units – the units referred to in PG&E’s GRC or other proceedings.

Note: For additional details see Exhibit (PG&E-3), WP GO-LOCTM-F.

Tables 1-16 and 1-17 below show the cost estimates, risk reduction values and CBRs for the mitigation work planned for the 2027-2030 period.

TABLE 1-16
MITIGATION COST ESIMATES, RISK REDUCTION, CBR AND FACTORS AFFECTING SELECTION
2027-2030 EXPENSE

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[a]				
Line No.	Mitigation ID	Control Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[b] [C]/([A]+[B])	Factors Affecting Selection
1	LOCTM-M003	Non-TIMP Strength Testing	$12,655	$12,402	$12,154	$11,911	$311.2	$2.5	$12.3	<0.1	Risk Tolerance, Operational and Execution Considerations
2		Total	$12,655	$12,402	$12,154	$11,911					

(a) NPV uses a base year of 2023.
(b) CBR calculations include allocated Foundational Activity Program costs.
Note: For additional details, see Exhibit (PG&E-3), WP GO-LOCTM-F.
The cost estimates in this table are generally based on PG&E’s 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

TABLE 1-17
MITIGATION COST ESIMATES, RISK REDUCTION, CBR AND FACTORS AFFECTING SELECTION
2027-2030 CAPITAL

Line No.	Control No.	Control Name	Thousands of Nominal Dollars 2027	2028	2029	2030	Millions of Dollars (NPV)[a] Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[b] [C]/([A]+[B])	Factors Affecting Selection
1	LOCTM-M001	Vintage Pipe Replacement	$2,000	$2,056	$2,115	$2,174	$7.9	$0.0	$6.1	0.8	Risk Tolerance, Operational and Execution Considerations
2	LOCTM-M002	Shallow and Exposed Pipe (Including Water and Levee Crossings) Mitigation	6,807	6,997	7,199	7,400	26.8	0.3	0.7	<0.1	Compliance, Risk Tolerance, Operational and Execution Considerations
3	LOCTM-M003	Non-TIMP Strength Testing	70,381	72,343	74,429	76,514	311.2	2.5	12.3	<0.1	Compliance, Risk, Tolerance, Operational and Execution Considerations
4	LOCTM-M004	Valve Automation	17,541	18,030	18,550	19,069	69.1	-	31.5	0.5	Compliance, Risk Tolerance, Operational and Execution Considerations
5		Total	$96,730	$99,425	$102,292	$105,157					

(a) NPV uses a base year of 2023.
(b) CBR calculations include allocated Foundational Activity Program costs.

Note: For additional details see Exhibit (PG&E-3), WP GO-LOCTM-F.
The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

3. Factors Affecting Mitigation Selection

Tables 1-16 and 1-17 above summarize the planned cost, CBR and risk reduction score for each of the LOCTM risk mitigation programs during the 2027-2030 period, including the rationale for selecting the proposed mitigations. PG&E's mitigation program proposes to focus spending on the programs that reduce the greatest amount of risk.

Vintage Pipe Replacement has the highest CBR of the proposed mitigations, followed by Valve Automation, Shallow and Exposed Pipe (Including Water and Levee Crossings), and Non-TIMP Strength testing, respectively.

Additional information on the factors impacting selection of mitigations is provided below.

Compliance Requirements: In addition to addressing risk, each mitigation is designed to meet federal and state compliance requirements. PG&E uses an operational risk model compliant with 49 CFR, Transportation, Part 192—Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, Subpart O, "Gas Transmission Pipeline Integrity Management," to identify mitigation projects. The output of the model and subsequent analysis leads to the identification of work performed under the mitigation programs to address the LOCTM RAMP risk. Additional sections of federal code[7] require mitigations when certain conditions are met. The following federal or state code requirements[8] are applicable to the mitigations programs that address the LOCTM risk:

- Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service – 49 CFR 192.703
- 49 CFR 192.933 requires that PG&E take action to address integrity issues and 49 CFR 192.935 requires prevention and mitigation measures for identified hazards associated with shallow and exposed pipe

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[7] Code of Federal Regulations (CFR) Title 49, Transportation, Part 192—Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards.

[8] This list provides some, but not all applicable regulations or CPUC decisions.

- 49 CFR § 192.613, requires the mitigation of findings from continuing surveillance
- For jurisdictional water crossings, the master lease agreements between PG&E and the California State Lands Commission, initiated in 2012, require that all pipeline facilities—active, deactivated or retired—must be under surveillance, monitoring, and maintenance.
- Strength testing for non-TIMP purposes to accommodate requirements of:
- Pub. Util. Code Section 958;
- 49 CFR §192.624;[9] and
- 49 CFR §192.917(e)(3), where pipe lacks a Traceable, Verifiable, and Complete (TVC) record of a test[10]
- The Valve Automation Program addresses Commission requirements in D.11-06-017[11] and D.12-12-030,[12]
- In 2011, the California legislature mandated the installation of automatic shut off valves to reduce the damage from a GT pipeline failure within an HCA or active seismic earthquake fault.[13]

Risk Tolerance: The Commission has recognized the need for discussion and clear guidance on Risk Tolerance and has expressed its intention to address this topic in future Phases of the Risk OIR. In the meantime, PG&E's risk mitigation strategies are selected to ensure that safety remains PG&E's top priority even when the quantitative RAMP

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9 49 CFR §192.624, Maximum allowable operating pressure (MAOP) Re-Confirmation, is a new section of federal regulation that became effective on July 6, 2020. It provides six methods for reconfirming MAOP, with strength testing as one of the methods. However, when there is no is TVC record of a prior test, Pub. Util. Code § 958 requires PG&E to perform a strength test rather than any of the other available MAOP reconfirmation options.

10 49 CFR §192.917(e)(3), is a revised section of federal regulation that became effective on July 1, 2020. In HCAs, "an operator may consider manufacturing and construction related defects to be stable defects only if the covered segment has been subjected to hydrostatic pressure testing satisfying the criteria of subpart J of at least 1.25 times MAOP…" Therefore, a pipe can have a TVC record of a test, but still be required to be re-tested to satisfy the requirement of §192.917(e)(3).

11 D.11-06-017, p. 30, Conclusion of Law (COL) 9.

12 D.12-12-030, pp. 76-77 and p. 121, COL 12.

13 Pub. Util. Code § 957.

modelling indicates the costs are higher than the modeled value of risk reduction. All the mitigations for the LOCTM risk are to address the risk of catastrophic equipment failure that could result in a SIF.

- LOCTM-M001 – Vintage Pipe Replacement: This program is focused on mitigating vintage fabrication and construction threats where they interact with high land movement threats, where bending strain from ILI data is identified, or where we have both landslide and liquefaction threats. PG&E considers “vintage pipe” to include pipe manufactured or constructed and fabricated using certain historic practices that are no longer being used today. PG&E considered the advice from PHMSA advisory bulletin ADB-2019-02 in this mitigation.
- LOCTM-M002 – Shallow Pipe and Exposed Pipe (Including Water and Levee Crossings): While the CBR score for this mitigation is low compared to the other planned mitigations, the mitigation programs help PG&E to address risks due to shallow and exposed pipe on both land and locations of levee/water crossings. The two programs identify, prioritize and mitigate pipeline that has insufficient cover, is vulnerable to damage or exposure from third parties, or has become exposed due to natural forces. Shallow pipe focuses on pipe segments with ≤12-inches of cover, in an agriculture or heavy cultivation area, high wheel loading concern, or ≤36-inches of cover in a navigable waterway. Exposed pipe focuses on pipe segments that have become unintentionally exposed within agriculture areas, roadways, navigable waterway, or span stress ≥ 50% SMYS. Due to the dynamic nature of pipe cover levels a mitigation project can be given preferred priority if such as an event includes but is not limited to an abnormal operating condition. The pipe segments addressed by these programs have a higher risk (especially for TPD and WROF drivers), relative to other segments within the tranches, leading to underestimations of CBR. This program enhances public safety and improves system reliability by identifying and evaluating hazards such as soil erosion, third-party damage threats, and other geohazards to buried pipeline installations located under waterways and within levee structures. This mitigation program is

informed by several best practices.[14] Studies conducted after Hurricane Katrina on levee systems nationwide identified California levee systems as among the most vulnerable for failure and have the greatest potential risk for loss of life, property damage, and economic impact.

- LOCTM-M003 – Non-TIMP Strength Testing: Non-TIMP Strength testing of pipelines is conducted to establish MAOP and manage specified threats to integrity of pipeline systems. Strength tests are conducted as a qualifying test for MAOP and to assess integrity for reasons that may include the following:
  - New construction or pipeline replacement;
    - Increase in or MAOP (uprating);
    - Conversion to service or change in product;
    - Class location changes (gas pipelines);
    - A section of pipe lacks a TVC record of a test that supports the MAOP; or
    - Verify that pipeline threats are being adequately managed, such as an integrity assessment under Subpart O.

  The Strength Testing program mitigates resident manufacturing and construction threats and SCC by strength testing the pipe to confirm its integrity in the presence of manufacturing defects, such as lack of fusion in a seam weld and SCC.
- LOCTM-M004 – Valve Automation: PG&E's Valve Automation Program is designed to enhance emergency response in the event of a GT pipeline rupture. This program continues to build upon the scope and principles that the Commission approved in D.12-12-03015, Pub. Util. Code section 957, and in PG&E's 2015 and 2019 GT&S Rate Cases. This program also builds on the National Transportation Safety Board (NTSB) safety recommendation P-11-27[16]. While not addressing the

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[14] These best practices are discussed in PG&E's 2019 GT&S Rate Case, A.17-11-009, Prepared Testimony (Sept. 12, 2018), p. 5-101, line 25 to p. 5-102, line 12.

[15] D.12-12-030, pp. 76-77 and p. 121, COL 12.

[16] NTSB, Safety Recommendation P-11-027, available at: <https://data.ntsb.gov/carol-main-public/sr-details/P-11-027> (accessed May 3, 2024).

risk of pipeline failure, installation of automated isolation capability on major pipelines in heavily-populated areas increases emergency preparedness, and may reduce property damage, the danger to emergency personnel and the public in the event of a pipeline rupture. It also complies with D.11-06-017.[17] The Valve Automation Program not only addresses Commission requirements in D.11-06-017 and D.12-12-030, but also allows PG&E to achieve the following Interstate Natural Gas Association of America industry objectives: (1) an Incident Mitigation Management plan producing a 1 hour response time for pipes greater than or equal to 12 inch diameter in HCAs and Class 3 and 4 non HCAs; and (2) an Incident Mitigation Management plan for those pipes with diameter less than 12 inches by 2030.

Operational and Execution Considerations: PG&E's proactive mitigations LOCTM-M001 to M004 (replacement of vintage pipe, replacement of shallow and exposed pipe, non-TIMP strength testing, and valve automation) demonstrate a prudent risk-informed asset management approach to managing asset risk before the pipelines experience failure. While these four programs have CBR scores less than 1, PG&E believes it is important to continue replacing or deactivating high risk assets, strength testing pipe, and automating valves as part of a long-term risk reduction approach to avoid the point in which leaks or ruptures occur at a rate that threatens public safety, exceeds public or regulatory risk tolerance, and exceeds a reasonable cost burden that limits funding in other expense controls and mitigations.

E. Alternative Mitigations Analysis

In addition to the proposed mitigations described in Section D above, PG&E considered alternative mitigations as well. The mitigations described in Section D constitute the Proposed Plan. The Alternative Plans consist of a combination of some or all of the proposed mitigations along with the alternative mitigation(s). The alternative plans maintain the proposed program pace and $ for each proposed control, mitigation and foundational activity, while adding additional mitigation(s). No tradeoffs were considered (e.g., reducing existing

[17] D.11-06-017, p. 30, COL 9.

program funding to fund an alternative proposal). PG&E describes each of the alternative mitigations it considered below and then provides Table 1-18 and 1-19 showing the cost estimates, risk reduction values, and CBRs for each of the Alternative Plans.

1. <u>Alternative Plan 1</u>: LOCTM-A001 – Mitigate Transmission Pipeline Impacted by Climate Change

This alternative proposes to mitigate impacts of climate change from predicted increases in flooding and heavy precipitation, which might cause coastal flooding, delta levee breaches, landslides, scour near waterways, and erosion hazards. These climate impacts would be mitigated by relocating pipelines or hardening through anchoring or concrete coating of at-risk pipelines. This alternative is informed by PG&E's CAVA.

This CAVA report documents simulations of different flooding and heavy precipitation scenarios across the five regions. It includes analyses of the location of existing natural gas transmission pipelines and associated infrastructure to identify locations of possible vulnerability to inundation damage associated with extreme storms. Sensitivities to flooding and precipitation hazards may include pipe buoyancy strain, bending strain, impact forces from soil and debris flows, hydrodynamic strain, or harmonic vibrations.

Transmission pipe within all present-day Federal Emergency Management Agency (FEMA) 100- and 500-year floodplains may see increased exposure to flooding as heavy precipitation events are projected to become more frequent in many parts of the service area.

Based on FEMA 100-year and 500-year storm events, PG&E identified 36 miles that could be targeted for intervention over a 27-year period. The program would prioritize replacement of pipe in those areas that present the higher risk.

PG&E assumed the cost of intervention to address the 36 miles of pipeline would be equivalent to its vintage pipe replacement program.

PG&E conducts an existing geohazards program. The primary difference between the geohazards program and this alternative mitigation is that the geohazards program is generally reactive to weather events by monitoring and mitigating actual damage, whereas this alternative mitigation would proactively identify higher risk locations and replace or harden pipelines before severe storm events occur.

This cost estimate is preliminary, based on information readily available and supplemented with SME judgment. A more in-depth analysis would be required to better estimate the costs associated with this program.

PG&E is not pursuing this alternative mitigation at this time because PG&E has prioritized its work plan to address more immediate concerns. PG&E would need to perform additional studies to obtain a better understanding of the potential impact to our transmission pipeline system due to increased flooding and precipitation caused by modeled climate change impacts.

TABLE 1-18
2027-2030 ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[a]		
Line No.	Mitigation No.	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	LOCTM-A001	Mitigate Transmission Pipeline Impacted by Climate Change	$31,301	$32,240	$33,207	$34,203	$123.6	$1.5	<0.1
2		Total	$31,301	$32,240	$33,207	$34,203			

(a) NPV uses a base year of 2023.

Notes: For additional details see Exhibit (PG&E-3), WP GO-LOCTM-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

2. **Alternative Plan 2: LOCTM-A002 – Mitigate Transmission Pipeline With Strong A-NN SCC and SSWC threats**

This mitigation considers replacing pipelines with Strong[18] Axial Near-Neutral Stress Corrosion Cracking (A-NN SCC)) and SSWC threats. This program would reduce the risk of A-NN SCC and SSWC damage to transmission pipeline assets, improving the longevity of the steel pipeline system. The total for Alternative Plan 2 is the Proposed Plan (mitigations described in Section D) plus Alternative Plan 2 (Proposed + A2).

These threats are emerging throughout the industry and PG&E is detecting more of these anomalies than historically detected. ILI tool detection and in-the-field DA methods have advanced to better detect these specific threats. With this technological advancement in threat detection, PG&E is considering the relevance of a pipe replacement program targeted at mitigating these threats.

The mitigation scope includes replacement of pipe that contains the strong A-NN SCC and strong SSWC threats, as identified in the TIMP Working Assessment Plan. The total mitigation would include 86 miles of pipe replacement consisting of 34 miles of pipe with strong SSWC, and 52 miles of pipe with strong A-NN SCC. The program would prioritize higher consequence and IOC.

Mileage forecast, annual pace, for this alternative is based on 1 percent of the 86-mile priority mileage per year, or 0.86 miles each year starting in 2027.

Table 1-19 below lists the mitigation, CBR and estimated costs to replace pipelines with Strong A-NN SCC and SSWC threats.

18 “Strong” susceptibility as determined by the TIMP risk model as documented in TD-4810P-16.

TABLE 1-19
2027-2030 ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[a]		
Line No.	Mitigation No.	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	LOCTM-A002	Replacement of pipelines with Strong A NN SCC and, SSWC threats	$20,189	$20,795	$21,419	$22,061	$79.7	$18.6	0.2
2		Total	$20,189	$20,795	$21,419	$22,061			

(a) NPV uses a base year of 2023.

Notes: For additional details see Exhibit (PG&E-3), WP GO-LOCTM-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

PACIFIC GAS AND ELECTRIC COMPANY

RISK ASSESSMENT AND MITIGATION PHASE

CHAPTER 2

RISK ASSESSMENT AND MITIGATION STRATEGY: LOSS OF CONTAINMENT ON GAS DISTRIBUTION MAIN OR SERVICE

PACIFIC GAS AND ELECTRIC COMPANY
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RISK ASSESSMENT AND MITIGATION STRATEGY: LOSS OF CONTAINMENT ON GAS DISTRIBUTION MAIN OR SERVICE

A. Executive Summary

Loss of containment (LOC) on Gas Distribution Main or Service risk is defined as a leak on a distribution main or service asset with the potential for migration and ignition. The drivers for this risk event are corrosion, natural forces, excavation damage, other outside force damage, material/weld fail, equipment failure, incorrect operations, cross bore, or other events that could threaten the integrity of the pipeline. Cross-cutting factors that impact the risk event are Physical Attack, Records and Information Management (RIM) and Seismic.

Exposure to this risk is based on approximately 112,639 miles of distribution main and service pipe, approximately 3.6 million gas risers, and approximately 750,519 potential legacy cross bore inspections remaining.[1] The risk model includes approximately 28,726 risk events each year. Most of the risk events are minor LOC events (leaks) that account for 77 percent of the total risk. Those risk events which are defined as major LOC events make up 23 percent of the total risk.

The top three risk drivers—incorrect operation, corrosion, and equipment failure—are responsible for 65 percent of the risk. Excavation damage, material/weld fail, natural forces, other, other outside force, and cross bore are responsible for 33 percent of the risk combined. Cross-cutting factors Physical Attack, RIM, and Seismic are responsible for 2 percent of the risk combined. The mitigations Pacific Gas and Electric Company (PG&E or the Company) plans to implement from 2027-2030 are designed to address the risk drivers noted above.

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1 Service pipe refers to gas lines connecting from the main to customer-connected equipment. Service pipe include single customer and branch services. Risers connect underground service lines to the above-ground meter set.

PG&E identified 42 tranches for the LOC on Gas Distribution Main or Service risk event. Sixteen of the tranches are separated by asset type (main), material type, vintage, population density, and whether it was recommended for Distribution Integrity Management Program (DIMP) mitigation analysis (MA). Eight of the tranches are separated by asset type (service), material type, vintage, and population density. Sixteen of the tranches are separated by asset type (riser), materials type, vintage, population density, and whether that riser resides indoor or outdoor. The other two tranches represent cross bore events inside and outside San Francisco. The PG&E DIMP utilizes a separate and discrete federal code compliant operational risk model to identify risk down to the pipe segment level taking into consideration the eight federal code required threats along with other factors to the pipe.[2]

LOC on Gas Distribution Main or Service has the eleventh-highest 2027 Test Year (TY) Baseline Safety Risk Score ($19.0 million) and the twelfth-highest 2027 TY Baseline Total Risk Score ($106.7 million) of PG&E’s 32 Corporate Risk Register (CRR) risks. For 2027-2030, the mitigation programs that have the highest aggregate risk reduction are Pipeline Replacement Program (Plastic) (LOCDM-M002) and Pipeline Replacement (Steel) (LOCDM-M001).

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[2] Code of Federal Regulations (CFR) Title 49, Transportation, Part 192—Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, Subpart P, “Gas Distribution Pipeline Integrity Management.”

1. Risk Overview

TABLE 2-1
RISK DEFINITION, SCOPE, AND DATA SOURCES

Line No.	Risk Name	LOC on Gas Distribution Main or Service
1	Definition	Failure of a gas distribution main or service resulting in a LOC, with or without ignition, that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, or the inability to deliver natural gas (NG) to customers.
2	In Scope	Failure of a distribution pipeline that leads to a minor or major LOC.
3	Out of Scope	A LOC driven by large over pressure events and customer-connected equipment.
4	Data Quantification Sources	RiskFinder likelihood of failure estimates, Pipeline and Hazardous Materials Safety Administration (PHMSA) Reportable Incident Data, Legacy Cross Bore program inspection data, PG&E's 2023 General Rate Case (GRC) application, PG&E Gas Distribution Geographic Information System, PG&E gas distribution leak data, PG&E Customer Outage Data, 2020 United States census block data, PG&E unit cost information from its 2023 GRC.

PG&E monitors the gas distribution system assets through operations and maintenance activities including atmospheric corrosion inspections, cathodic protection (CP) system monitoring, leak survey, leak repair, abnormal operating condition inspection, and excavation damage prevention efforts. PG&E performs additional monitoring, risk assessment and mitigation activities using a federal code-compliant DIMP and operational risk model.[3]

Along with system monitoring, PG&E mitigates distribution main and service risk through tee cap replacements, valve installations and replacements, and legacy cross bore inspections. PG&E also performs gas distribution pipeline replacement as part of a long-term asset management strategy to mitigate the effects of aging infrastructure within the gas distribution system. PG&E's long-term asset management strategy to

[3] CFR Title 49, Transportation, Part 192—Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, Subpart P, "Gas Distribution Pipeline Integrity Management."

mitigate the effects of aging infrastructure strives to take a holistic approach incorporating the condition of the assets and the risks to the assets and implementing risk mitigation programs over time. Absent prudent asset management, there will be a point in time where the asset condition degrades to the point where the number of LOC events exceeds the capacity of the skilled and qualified workforce and exceeds a reasonable cost burden that rate payers are expected to be willing to pay over a short period of time to replace, repair, or deactivate the failed assets. This could result in an increase to the number of significant incidents because of increased LOC on these aging assets.

B. Risk Assessment

1. Background and Evolution

In the 2020 Risk Assessment and Mitigation Phase (RAMP), PG&E presented one combined gas distribution risk event that includes both cross bore and non-cross bore risk events. The LOC due to a cross bore is the driver of the cross bore tranche.

The risk event definition was expanded in the 2020 RAMP to include both “with ignition” and “without ignition.” By expanding the definition to include “without ignition” in the risk event, PG&E was able to improve risk model accuracy by using more PG&E historical system data, since most of the gas distribution LOC events do not result in an ignition but contribute to the risk consequences.

In the 2020 RAMP, PG&E modeled the new combined risk event using the eight drivers based on Title 49 of the CFR – Transportation Part 192, Subpart P.

In the 2023 GRC, PG&E refreshed the model inputs for all data sources with 2020 information. PG&E also changed the risk model frequency data from historical leak rates to PG&E’s DIMP model leak rate projections, which is based on historical leak data plus additional data sources. This change allowed PG&E to better align the LOC on Gas Distribution Main or Service risk model with PG&E’s DIMP operational risk model. The source data used to represent the consequence distributions was unchanged from the PG&E’s 2020 RAMP Report. Lastly, the safety consequence methodology was refined to determine the severity of a potential significant LOC at the individual risk driver level. These changes were all PG&E initiated.

In addition, PG&E increased the number of tranches for this risk by going from 12 tranches in the 2020 RAMP Report to 34 tranches. For mains, services and risers made of steel material, further tranching based on pre- and post-1941 vintage was created. For mains, services and risers made of plastic material, further tranching based on pre- and post-1985 vintage was created. Risers were further tranched into indoor and outdoor locations. The increase in tranches provides more granularity into this risk from a vintage perspective for distribution main, services and risers, as well as more granularity for risers with respect to indoor and outdoor locations.

In the 2024 RAMP, PG&E refreshed the model inputs for all data sources with 2022 information. PG&E also increased the number of tranches for this risk by going from 34 tranches to 42 tranches. For mains, a dimension was added to indicate whether the assets have been recommended by DIMP to be further evaluated through its MA process. The recommended assets are higher risk assets, which may be candidates for pipeline replacement programs.

Finally, in D.23-12-003, p. 48, Ordering Paragraph 4, the California Public Utilities Commission (CPUC or Commission) approved PG&E's Transmission Definition change. The analysis in this chapter does not incorporate this change. PG&E is in process of analyzing this change and it will include any impacts in its 2027 GRC filing.

2. Risk Bow Tie

FIGURE 2-1
RISK BOW TIE

Drivers

Drivers	Freq (Events/Yr)	% Freq	% Risk
Incorrect Operation	3,202	11%	23%
Corrosion	4,038	14%	21%
Equipment Failure	15,959	56%	21%
Excavation Damage	1,779	6.2%	12%
Material/Weld Fail	1,616	5.6%	9.1%
Natural Forces	658	2.3%	6.8%
Other	678	2.4%	4.1%
CC - Seismic scenario	84	0.3%	1.4%
Other Outside Force	483	1.68%	0.9%
CC - RIM	222	0.8%	0.8%
Crossbore	0.9	0.003%	0.30%
CC - Physical Attack	6	0.02%	0.02%
Aggregated	**28,726**	100%	100%

Exposure

112,639
Miles main, service pipe

3,576,290
Count risers

750,519
Crossbore inspections

Loss of Containment on Gas Distribution Main or Service

TY Baseline
Risk Value
for 2027

$106.7M
(2023 $, risk-adjusted)

Outcomes

Outcomes	CoRE	%Freq	%Risk
Minor - Equipment Failure	0.001	56%	19%
Minor - Corrosion	0.005	14%	17%
Minor - Incorrect Operation	0.005	12%	17%
Minor - Excavation Damage	0.005	6.2%	9%
Minor - Material/Weld Fail	0.005	5.6%	7.3%
Major - Incorrect Operation	13	0.002%	7.2%
Major - Corrosion	7.2	0.002%	4.1%
Major - Natural Forces	27	0.0005%	3.6%
Minor - Natural Forces	0.01	2.3%	3.2%
Minor - Other	0.005	2.4%	3.1%
Major - Excavation Damage	7.1	0.002%	3.1%
Major - Equipment Failure	6.5	0.001%	2.0%
Major - Material/Weld Fail	9.5	0.001%	1.8%
Major - Other	11	0.0003%	0.9%
Minor - Seismic	0.012	0.3%	0.9%
Minor - Other Outside Force	0.001	1.7%	0.6%
Major - Seismic	24.7	0.0001%	0.5%
Major - Crossbore	12	0.0001%	0.3%
Major - Other Outside Force	8.5	0.0001%	0.3%
Minor - Crossbore	0.02	0.003%	0.01%
Aggregated	**0.0037**	100%	100%

a. Difference From 2020 Risk Bow Tie

In the 2020 RAMP, PG&E presented one gas distribution LOC risk with cross bores represented at the tranche level.

In the 2020 RAMP, the risk event included both with and without ignition to better align with PG&E's history with distribution LOC events. By redefining the risk event to include without ignition, PG&E was able to rely on PG&E data to model the risk event and consequences as opposed to relying on industry data.

The risk drivers for both the 2020 and 2024 RAMP risk event are the same, except for the removal of the cross-cutter, Skilled and Qualified Workforce.

3. Exposure to Risk

For the LOC on Gas Distribution Main or Service risk event, exposure to risk is measured by the total distribution equipment units. This is based on approximately 112,639 miles of distribution main and service pipe, approximately 3.6 million gas risers, and approximately 750,519 potential legacy cross bore inspections remaining.[4] For the cross bore tranches, risk exposure is based on an estimated number of potential legacy cross bores inspections remaining in PG&E's system.

4. Tranches

PG&E identified 42 total tranches for the LOC on Gas Distribution Main or Service risk event. Sixteen of the tranches are separated by asset type (main), material type, vintage, population density, and whether it was recommended for DIMP MA due it the DIMP Model risk ranking. Eight of the tranches are separated by asset type (service), material type, vintage, and population density. Sixteen of the tranches are separated by asset type (riser), materials type, vintage, population density, and whether that riser resides indoor or outdoor. The other two tranches represent cross bore events inside and outside San Francisco.

The factors provide a foundation for evaluating the likelihood of a LOC risk event based on large tranches of asset type, material type, and MA status and the consequences of a risk event considering major/minor outcome, severity grouping, asset type, population density, and indoor/outdoor location characteristics. However, the limitations of these factors should be noted as they rely on past performance, which is not an exact predictor of future outcomes, especially over long periods of time as these assets are expected to operate under.

Additional tranching by pipeline installation year is not warranted. When comparing normalized likelihood of failures using the 2022 DIMP operational risk model results, pre-1975 plastic pipelines and pre-1924 steel pipelines exhibit 33 percent and 16 percent higher values, respectively, relative to 1975-1984 plastic and 1924-1940 steel. However, the likelihood of failure is 51 percent higher for pre-1985 plastic compared to 1985 and newer plastic,

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4 For RAMP risk model purposes, it is assumed that there is one riser for every service.

and 46 percent higher for pre-1941 steel compared to 1941 and newer steel. Therefore, additional parsing of the pre-1985 plastic and pre-1941 steel is not necessary as pre-1985 and pre-1941 appropriately identify the population of pipe with the highest leak rates. The pre-1941 designation and the pre-1985 designation align with populations of pipe with higher likelihoods of failure as compared with more modern installation years and the pre-1941 and pre-1985 align with existing established PG&E programs.[5] The CPUC Hazard Analysis & Mitigation Report On Aldyl-A Polyethylene Gas Pipelines in California, dated June 11, 2014, outlines history of Aldyl-A pipes with a table summarizing several different vintages and resins of Aldyl-A with their corresponding resistance to slow crack growth.[6] All Aldyl-A plastic vintages prior to 1984 have a medium to low relative resistance to slow crack growth. Without specificity within historical documentation related to resin type or other data attributes such as manufacturing date, PG&E has leveraged a conservative approach to its pipe replacement program that assumes all plastic pipe pre-1985 is more leak-prone due to its lower relative resistance to slow crack growth. PHMSA has also notified operators of the risks associated with vintage plastic pipelines and recommended mitigating these risks.[7] It is not necessary to perform additional tranching based on pipeline installation year provided these current populations of pre-1941 steel and pre-1985 plastic have higher likelihoods of failure as compared with more modern installation years and in the case with plastic pipe, align with federal and state warnings that the pre-1985 pipe is of higher likelihood of failure.

PG&E continues to improve its RAMP model. One change that PG&E is evaluating is to build out seismic modifiers to improve the model's capabilities related to the seismic scenario. Utilizing information from previous seismic events, PG&E is looking to build out unitless modifiers to

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5 GP-1102, Gas Distribution Mains and Services Asset Management Plan, is available on request.

6 CPUC's Hazard Analysis & Mitigation Report on Aldyl-A Polyethylene Gas Pipelines in California (June 11, 2014).

7 PHMSA's Advisory Bulletins: ADB-99-02 (Oct. 1, 1999); ADB-02-07 (Nov. 26, 2002); and ADB 07-01 (Sept. 6, 2007).

calibrate the model to pre-existing events. Additionally, PG&E will continue to seek quantitative data sources for areas of the model currently utilizing qualitative data inputs.

Table 2-2A shows the percent exposure, risk score components and percent risk by asset type at the tranche level, and Table 2-2B shows total risk score per unit exposure for main replacement and service tranches.

TABLE 2-2A
PERCENT EXPOSURE, RISK VALUE, AND PERCENT RISK BY TRANCHE AND ASSET TYPE
LOC – GAS DISTRIBUTION MAIN OR SERVICE

Line No.	Tranche	Exposure (%)	Safety Risk Value ($M)	Gas Reliability Risk Value ($M)	Financial Risk Value ($M)	Aggregated Risk Value ($M)	Risk (%)
1	Crossbore - San Francisco	0.251%	1.02E-02	4.19E-05	1.02E-03	1.13E-02	1.06E-04
2	Crossbore - Non San Francisco	16.654%	0.283	0.003	0.026	0.312	0.29%
3	Main - Steel Installed < 1941 - Population Density High - MA Yes	0.006%	0.127	0.080	0.512	0.719	0.67%
4	Main - Steel Installed < 1941 - Population Density Low - MA Yes	0.001%	0.008	0.010	0.063	0.081	0.08%
5	Main - Steel Installed >= 1941 - Population Density High - MA Yes	0.024%	0.389	0.254	1.572	2.215	2.08%
6	Main - Steel Installed >= 1941 - Population Density Low - MA Yes	0.003%	0.026	0.035	0.212	0.273	0.26%
7	Main - Plastic Installed < 1985 - Population Density High - MA Yes	0.016%	0.190	0.083	0.412	0.684	0.64%
8	Main - Plastic Installed < 1985 - Population Density Low - MA Yes	0.004%	0.006	0.005	0.025	0.036	0.03%
9	Main - Plastic Installed >= 1985 - Population Density High - MA Yes	0.025%	0.193	0.104	0.496	0.793	0.74%
10	Main - Plastic Installed >= 1985 - Population Density Low - MA Yes	0.003%	0.012	0.013	0.063	0.088	0.08%
11	Main - Steel Installed < 1941 - Population Density High - MA No	0.019%	0.496	0.320	2.020	2.836	2.66%
12	Main - Steel Installed < 1941 - Population Density Low - MA No	0.014%	0.188	0.246	1.536	1.970	1.85%
13	Main - Steel Installed >= 1941 - Population Density High - MA No	0.185%	1.996	1.394	8.621	12.011	11.26%
14	Main - Steel Installed >= 1941 - Population Density Low - MA No	0.194%	1.039	1.461	8.969	11.469	10.75%
15	Main - Plastic Installed < 1985 - Population Density High - MA No	0.047%	0.787	0.365	1.788	2.939	2.75%
16	Main - Plastic Installed < 1985 - Population Density Low - MA No	0.076%	0.613	0.585	2.853	4.050	3.80%
17	Main - Plastic Installed >= 1985 - Population Density High - MA No	0.150%	0.844	0.491	2.291	3.626	3.40%
18	Main - Plastic Installed >= 1985 - Population Density Low - MA No	0.220%	0.602	0.716	3.318	4.636	4.34%
19	Service - Steel Installed < 1941 - Population Density High	0.059%	0.584	0.116	1.637	2.337	2.19%
20	Service - Steel Installed < 1941 - Population Density Low	0.058%	0.252	0.114	1.617	1.983	1.86%
21	Service - Steel Installed >= 1941 - Population Density High	0.178%	1.229	0.264	3.710	5.203	4.88%

TABLE 2-2A
PERCENT EXPOSURE, RISK VALUE, AND PERCENT RISK BY TRANCHE AND ASSET TYPE
LOC – GAS DISTRIBUTION MAIN OR SERVICE
(CONTINUED)

Line No.	Tranche	Exposure (%)	Safety Risk Value ($M)	Gas Reliability Risk Value ($M)	Financial Risk Value ($M)	Aggregated Risk Value ($M)	Risk (%)
22	Service - Steel Installed >= 1941 - Population Density Low	0.210%	0.639	0.313	4.411	5.363	5.03%
23	Service - Plastic Installed < 1985 - Population Density High	0.145%	1.665	0.284	4.019	5.968	5.59%
24	Service - Plastic Installed < 1985 - Population Density Low	0.184%	0.976	0.382	5.416	6.773	6.35%
25	Service - Plastic Installed >= 1985 - Population Density High	0.349%	2.833	0.510	7.153	10.495	9.83%
26	Service - Plastic Installed >= 1985 - Population Density Low	0.367%	1.312	0.536	7.535	9.382	8.79%
27	Riser - Indoor - Steel Installed < 1941 - Population Density High	0.203%	0.025	0.000	0.024	0.049	0.05%
28	Riser - Indoor - Steel Installed >= 1941 - Population Density High	0.419%	0.039	0.001	0.050	0.090	0.08%
29	Riser - Indoor - Plastic Installed < 1985 - Population Density High	0.409%	0.036	0.001	0.044	0.080	0.07%
30	Riser - Indoor - Plastic Installed >= 1985 - Population Density High	0.808%	0.083	0.001	0.098	0.182	0.17%
31	Riser - Outdoor - Steel Installed < 1941 - Population Density High	2.834%	0.099	0.004	0.319	0.422	0.40%
32	Riser - Outdoor - Steel Installed >= 1941 - Population Density High	8.842%	0.278	0.014	0.994	1.286	1.20%
33	Riser - Outdoor - Plastic Installed < 1985 - Population Density High	7.243%	0.186	0.010	0.704	0.901	0.84%
34	Riser - Outdoor - Plastic Installed >= 1985 - Population Density High	18.075%	0.455	0.027	1.885	2.368	2.22%
35	Riser - Indoor - Steel Installed < 1941 - Population Density Low	0.110%	0.006	0.000	0.013	0.019	0.02%
36	Riser - Indoor - Steel Installed >= 1941 - Population Density Low	0.328%	0.014	0.001	0.040	0.054	0.05%
37	Riser - Indoor - Plastic Installed < 1985 - Population Density Low	0.303%	0.012	0.001	0.035	0.047	0.04%
38	Riser - Indoor - Plastic Installed >= 1985 - Population Density Low	0.303%	0.014	0.001	0.037	0.051	0.05%
39	Riser - Outdoor - Steel Installed < 1941 - Population Density Low	2.751%	0.042	0.004	0.312	0.358	0.34%
40	Riser - Outdoor - Steel Installed >= 1941 - Population Density Low	10.215%	0.142	0.016	1.155	1.314	1.23%
41	Riser - Outdoor - Plastic Installed < 1985 - Population Density Low	9.013%	0.107	0.013	0.928	1.048	0.98%
42	Riser - Outdoor - Plastic Installed >= 1985 - Population Density Low	18.699%	0.208	0.028	1.953	2.189	2.05%
43	Total	100%	19.042	8.805	78.866	106.713	100%

TABLE 2-2B
MAIN REPLACEMENT AND SERVICE TRANCHES RISK BY AGGREGATE RISK VALUE

				Risk Score/Miles ($000)			
			Population Density	Plastic		Steel	
				Installed < 1985	Installed >= 1985	Installed < 1941	Installed >= 1941
Main (miles)	Mitigation Analysis? →	No	High	1.397	0.543	3.433	1.462
			Low	1.195	0.475	3.114	1.333
		Yes	High	0.964	0.724	2.935	2.061
			Low	0.194	0.630	1.920	1.868
Service (miles)			High	0.928	0.677	0.895	0.658
			Low	0.830	0.576	0.776	0.575

5. Drivers and Associated Frequency

PG&E identified nine drivers, excluding the three cross-cutting factor drivers, and 30 sub-drivers for the LOC on Gas Distribution Main or Service risk event. The drivers are based on the PHMSA integrity management requirements for gas distribution pipeline systems (DIMP), 49 CFR Part 192, Subpart P and use the estimated likelihood of failure estimates from the DIMP Riskfinder model, with exception of Cross Bore and the three cross cutting drivers. Each driver and its associated 2027 TY baseline frequency are discussed below. A complete list of sub-drivers is provided in supporting workpapers.

- D1 – Incorrect Operations: Incorrect operations include failure due to inadequate procedures or safety practices, or failure to follow correct procedures, or other operator error. This may lead to safety hazards when procedures are not followed or when improperly trained or untrained personnel perform work on the distribution system (e.g., failure to follow standards and procedures for installing new plastic pipe can result in construction defects). Incorrect operations accounted for 3,202 (11 percent) of the 28,726 expected annual number of events.
- D2 – Corrosion: Failure due to the deterioration of a substance, usually metal, resulting from an electrochemical reaction with its environment. Corrosion can, over time, reduce the wall thickness of the pipe resulting in the release of gas. Corrosion events accounted for 4,038 (14 percent) of the 28,726 expected annual number of events.

- D3 – Equipment Failure: Equipment failures may be from threaded components, flanges, collars, couplings and broken or cracked components, or from O-ring failures, gasket failures, seal failures, or failures in packing or similar leaks. Riser thread leaks because of thread dope deterioration are the primary events in this driver, primarily resulting in non-hazardous LOC events. Equipment related events accounted for 15,959 (56 percent) of the 28,726 expected annual number of events.
- D4 – Excavation Damage: Failure or previous damage due to excavation activity. Any excavation impact that results in the need to repair or replace an underground facility due to a weakening or the partial or complete destruction of the facility including, but not limited to, the protective coating, lateral support, CP or the housing for the line device or facility (e.g., third-party dig-ins). Excavation damage accounted for 1,779 (6 percent) of the 28,726 expected annual number of events.
- D5 – Material, Weld, or Joint Failure (Material/Weld Fail): Failure from material defect within the pipe, component or joint due to faulty manufacturing procedures, design defects, or in-service stresses such as vibration, fatigue, and environmental cracking. Material failure or pipe weld accounted for 1,616 (6 percent) of the 28,726 expected annual number of events.
- D6 – Natural Force Damage: Failure due to outside forces not involving humans, such as earth movement, landslides, subsidence, heavy rains/floods, lightning, temperature, thermal stress, frozen components, high winds (Including damage caused by impact from objects blown by wind), or other similar natural causes. Natural force damage accounted for 659 (2 percent) of the 28,726 expected annual number of events.
- D7 – Other: Other concerns that could threaten the integrity of the pipeline (e.g., a gas leak which is repaired by replacing the pipeline or service without exposing the leak source and the cause of the leak was undetermined). Other concerns accounted for 678 (2 percent) of the 28,726 expected annual number of events.

- D8 – Other Outside Force Damage: Failure due to outside force damage, other than excavation damage or natural forces, such as a vehicle impact on a riser. Other outside force damage accounted for 483 (2 percent) of the 28,726 expected annual number of events.
- D9 – Cross Bore: Failure due to use of trenchless technology installation of a gas asset that pierces a wastewater or storm drain system. Cross bore damage accounted for ~1 (<1 percent) of the 28,726 expected annual number of events. This is based on the estimated number of remaining legacy inspections, actual cross bore find rate from completed legacy inspections, and the actual number of LOC events experienced.

For a LOC on mains, services, and risers, PG&E used its RiskFinder likelihood of failure estimates for all drivers and sub-drivers. PG&E relied on leak data ranging from 5 to 15 years, depending on the sub-driver, because the data provided a representation of PG&E's current gas distribution system and was sufficient for representing leak sub-driver frequencies. Additional external datasets were also used to derive factors contributing to the likelihood of failure estimates. With this data, frequencies were developed for mains (steel and plastic), services (steel and plastic), and risers (all types).

6. Climate Adaptation Vulnerability Assessment Results

PG&E designed the Climate Adaptation Vulnerability Assessment (CAVA) to be consistent with the CPUC's Final Ruling on Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Change Adaptation (Rulemaking (R.) 18-04-019). The methodology outlined by Decision (D.) 20-08-046 requires utilities to perform an assessment of all assets, operations and services that will be impacted by future risks from climate change related to changes in temperatures, precipitation & flooding, sea level rise, wildfire, and drought driven subsidence.

PG&E's CAVA addresses actual or expected climatic impacts on the gas distribution system, with a focus on the 2050 decadal time period. The CAVA assessment on PG&E's Gas Distribution Assets considered impacts to utility planning, facilities maintenance and construction, and communications, to maintain safe, reliable, affordable, and resilient operations.[8] The CAVA results do not explicitly consider how climate change will directly impact the likelihood of a LOC event for gas distribution assets. Instead, the CAVA climate risk findings consider generalized impacts from future climate hazards to gas distribution pipelines that could have significant consequences for customers, public safety, and the environment, with impacts ranging from interrupted service to gas leaks, pipeline ruptures and combustion.

TABLE 2-3
GAS DISTRIBUTION CAVA CLIMATE RISK SCORES

Line No.	Climate Hazard	Adaptive Capacity	Climate Change Risk
1	Temperature	High	Low (off-ramped)
2	Flooding/Precipitation	Moderate	Moderate
3	Sea Level Rise	Moderate	Low (off-ramped)
4	Wildfire	High	Moderate
5	Drought-Driven Subsidence	High	Low (off-ramped)

The adaptive capacity of PG&E's gas distribution assets to future climate hazards were a key factor in determining the Company's climate risk rankings. Adaptive capacity was defined as the ability of an asset or system to moderate or eliminate identified climate vulnerabilities as assessed based on 2050 conditions and mitigate future impacts. This included any aspect of design, planning, operations, monitoring, emergency response capacities, and other PG&E capabilities. PG&E's CAVA (refer to Table 2-3 above) found that Gas Distribution current mitigations and controls result in high adaptive capacity to address climate risks associated with temperatures, wildfire, and drought-driven subsidence, and moderate adaptive capacity to address climate risks associated with flooding/precipitation and sea level rise.

7. Cross-Cutting Factors

A cross-cutting factor is a driver, component of a driver, or a consequence multiplier that impacts multiple risks. PG&E is presenting

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[8] PG&E's CAVA, Section 3.1.2.b Gas Distribution (to be published May 15, 2024).

seven cross-cutting factors in the 2024 RAMP. The cross-cutting factors that impact the LOC on Gas Distribution Main or Service risk event are shown in Table 2-4 below.

TABLE 2-4
CROSS-CUTTING FACTOR SUMMARY

Line No.	Cross-Cutting Factor	Impacts Likelihood	Impacts Consequence
1	Climate Change	Yes*	No
2	Cyber Attack	No	No
3	Emergency Preparedness and Response	No	Yes*
4	Information Technology Asset Failure	No	No
5	Physical Attack	Yes	No
6	RIM	Yes	Yes
7	Seismic	Yes	Yes

Yes The cross-cutting factor has been quantified in the model.

Yes* The cross-cutting factor does influence the baseline risk but has not been quantified in the model, or the cross-cutting factor may influence the baseline risk but further study is needed.

No The cross-cutting factor does not meaningfully influence the baseline risk.

A description of the cross-cutting factors and the mitigations and controls that PG&E is proposing to mitigate the cross-cutting factors is in Exhibit (PG&E-2), Chapter 3.

8. Consequences

The risk model measures the risk associated with a LOC on a gas distribution pipeline main, service, riser, or due to a cross bore. A LOC can result in public, employee, and contractor safety events, a reduction in gas reliability, and/or financial losses. Non-LOC consequences associated with the distribution system are not considered within the scope of this model and are included in Safety, Health, Enterprise Corrective Action Program (ECAP), and Department of Transportation (DOT),[9] Safety, Health, ECAP, DOT'S (SHED) Contractor, Employee, or Third Party- Safety Incident Risks (i.e., Moving Vehicle Incident, OSHA, or SIF event occurring as a result of an employee or contractor perform gas distribution work that is not the result of a gas distribution LOC event). Additionally, the risk associated with

9 Safety, Health, ECAP, and DOT (collectively, SHED).

customer connected equipment is considered its own risk event[10] and not included within the scope of this model.

PG&E modeled the consequence of a LOC on a main, service, riser, and cross bore with outcome and consequence distributions as described below.

The two outcomes of a gas distribution LOC event are defined in this model as “major” and “minor” where a major event is equivalent to a PHMSA significant incident, and a minor event is equivalent to a non-PHMSA significant incident. Per PHMSA, significant incidents are those including: (1) fatality or injury requiring in-patient hospitalization; and/or (2) $50,000 or more in total costs, measured in 1984 dollars.[11] Gas distribution incidents caused by an adjacent fire or explosion that impacts the pipeline system are excluded. The consequences for the distribution mains, services, and risers tranches and the cross bore tranche are distinct and explained below.

Along with tranches, this model also considers the consequences associated with each driver. For distribution mains, services, and risers, the probability of a major outcome was derived for each driver by dividing the number of PHMSA significant incidents by the total population of distribution leaks over the same time period.

A major LOC incident on a main, service, or riser can have safety, reliability, and/or financial consequences. A minor LOC can have only reliability and/or financial consequences.

The consequence distribution parameters were calculated using PG&E and industry data:

- Safety incident rates – Considering asset type and driver;
- Location of the asset – High and low population density; and
- Type of event – Classified as either major or minor.

The major and minor risk event outcomes and associated consequences are described below.

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10 Loss of Containment on Gas Customer Connected Equipment is one of the 32 risk events on PG&E’s CRR.

11 PHMSA, Pipeline incident flagged files, available at: https://www.phmsa.dot.gov/data-and-statistics/pipeline/pipeline-incident-flagged-files (accessed May 3, 2024).

a. Consequences for Outcome 1 – Major Event

<u>Safety Consequence</u>

The magnitude of the safety consequences associated with a gas distribution LOC is influenced by several factors. This model considers asset type, driver, and population density.

For asset type, this model considers the consequences associated with a LOC on a main, a service, and a riser independently. Injury and fatality rates per risk event were derived from historic PHMSA significant incidents on gas distribution. PG&E does not have sufficient PG&E-specific significant incident data to model all the tranches and factors. Therefore, PG&E calculated a safety incident rate using PHMSA's industry incident data, which included PG&E incidents, in the model. Injury and fatality rates vary depending on the cause or driver of the incident. Figure 2-2 summarizes the PHMSA significant incidents (count increases with lighter coloration) by number of total injuries and fatalities (total increases with data point size) between 1986 and 2022 and illustrates the historical range of fatalities and injuries from gas distribution LOC events. Figure 2-3 below depicts the destructive potential of a single LOC event where gas migrated into a multi-story building from an incorrect operation affecting 56 people (eight fatalities and 48 injuries).

FIGURE 2-2
1986-2022 PHMSA GAS DISTRIBUTION INCIDENTS WITH FATALITY OR INJURY

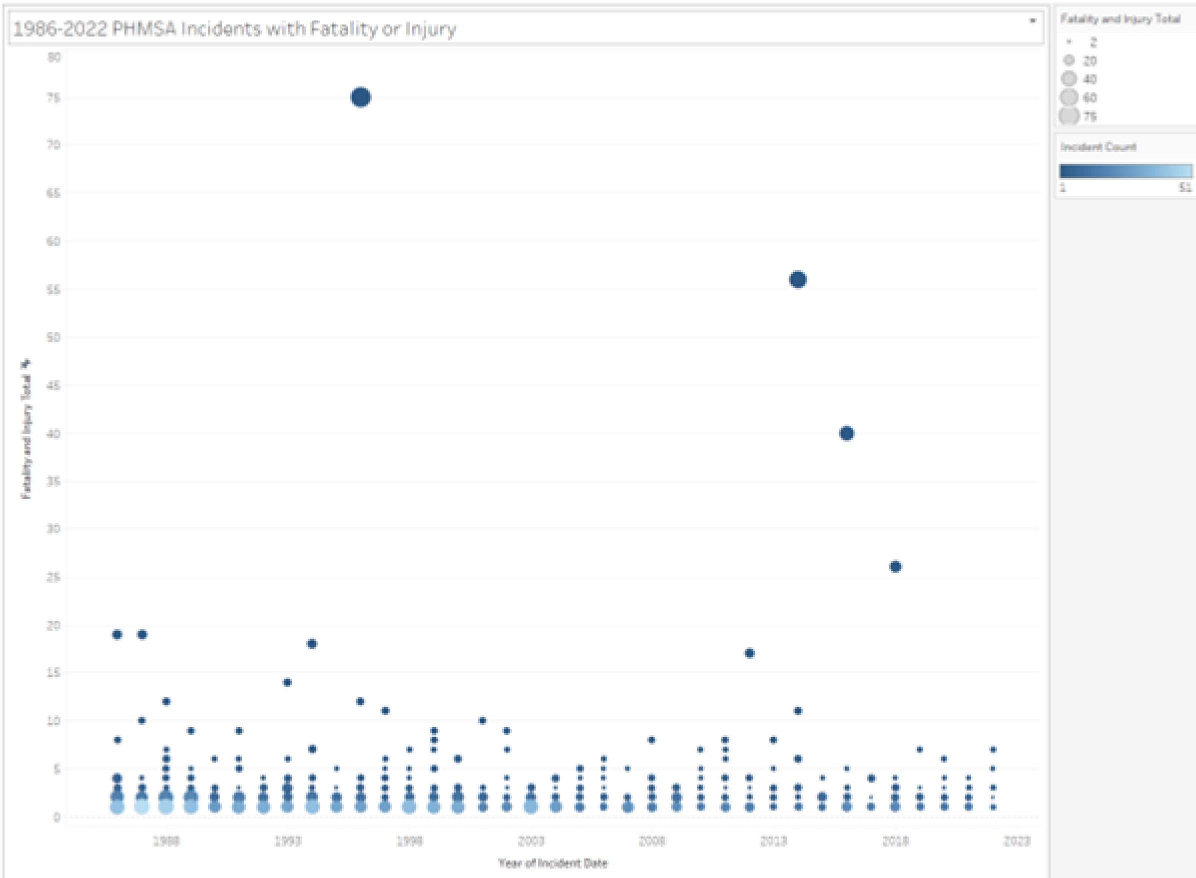

FIGURE 2-3
2014 EXPLOSION IN NEW YORK

The risk has been tranched to account for areas of high population (greater than or equal to 9,000 people per square mile, which aligns with the DIMP operational risk model) and low population (less than 9,000 people per square mile). PG&E's exposure of mains (metal and plastic), risers (metal and plastic), and services (all) were grouped into these two population density groups using GDGIS and 2020 census block data. To develop population consequence factors, PG&E used the reported address of each PHMSA incident and 2020 census block data to map each industry incident to a specific population density. Population factors were derived by normalizing the industry injury and fatality incident rates for mains, services, and risers in low and high population density areas to the overall aggregated industry injury and fatality rate-. In areas of high population density, the injury and fatality rate were 1.75 times the industry average rate (includes PG&E and non-PG&E incidents). In areas of low population density, the injury and fatality rate were 0.91 times the industry average rate (includes PG&E

and non-PG&E incidents).[12] These factors were applied to the asset and driver incident rates discussed above.

Reliability Consequence

PG&E used historic outage data (2011-2022) to represent the number of customers impacted by a major LOC event. To estimate the number of customers impacted, PG&E included historic reliability incidents where a PG&E LOC resulted in an injury or fatality or exceeded $50,000 in damages. Reliability consequences were derived for mains, services, and risers. PG&E recognizes further work is needed to assess the true reliability consequences to residential, commercial, industrial, and critical agency customers.

Financial Consequence

PG&E used historic PHMSA industry financial data (2004-2023) to estimate the financial consequences associated a significant LOC on a main, service, and riser for low and high population densities. Due to limited PG&E data, PG&E weighted the significant PG&E PHMSA reported financial data and non-PG&E industry financial data equally. All historical costs were adjusted for inflation and converted to 2023 dollars. PHMSA financial data is limited to publicly available information and is not inclusive of all costs associated with the incident (e.g., confidential settlement amounts; other carry-on costs associated with post-incident corrective actions).

b. Consequences for Outcome 2 – Minor Risk Event

Reliability Consequence

PG&E used historic outage data (2011-2022) to represent the number of customers impacted by a minor LOC event. To estimate the number of customers impacted, PG&E included all incidents except where a PG&E LOC resulted in an injury or fatality or exceeded $50,000 in damages. To estimate the probability of a minor LOC, PG&E divided the number of leaks that caused an outage by the total number of recorded leaks within the same time period.

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12 Reference workpaper: Exhibit (PG&E-3), WP GO-LOCDM-9, GRC Safety Consequence tab, Table Population Density Factor, Rows 97 & 101.

Financial Consequence

Using 2023 GRC unit costs, PG&E estimated the cost for repairing a leak associated with a minor LOC for mains, services, and risers.

c. Consequences for Cross Bore Tranches

Similar to the main, service and riser tranches, PG&E divided the cross bore risk into two different tranches, based on population density (San Francisco and Non-San Francisco) and into two outcomes (Major and Minor). To date, PG&E has observed- 36 LOC events due to cross bores from 1999-2022; however, none of these have been a “major” LOC event. To estimate the probability of a major event, PG&E assumed that the next cross bore event will be a “major” LOC; and therefore, estimated the probability of a major LOC of 1 out of 37 events (approximately 2.7 percent), and a minor LOC of 36 out of 37 events (97.3 percent).[13]

d. Consequences for Cross Bore Risk Event

Major Risk Event – Safety Consequence

PG&E has not observed a major LOC due to a cross bore. PHMSA industry data was used to estimate the safety consequences associated with a cross bore. PG&E reviewed the narrative of each PHMSA significant incident and included incident data where either: (1) a cross bore was confirmed to be the cause of the incident; or (2) the incident was caused by a gas migration through a sewer. A safety incident rate was derived from this subset of PHMSA data and supplemented with SME input. The population density factor was applied to this safety incident rate to estimate the safety incident rate in San Francisco (high population density) and Non-San Francisco (low population density).

Major Risk Event – Reliability Consequence

PG&E estimated the reliability consequences of a major cross bore event to be similar in magnitude to a major LOC on a service asset. As

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13 The method PG&E uses to estimate the probability of a major event was recommended by the Safety and Enforcement Division (SED) in its review of PG&E’s 2017 RAMP Report. I.17-11-003, SED’s Risk and Safety Aspects of RAMP Report of PG&E (Mar. 30, 2018), p. 53.

such, PG&E aligned the major cross bore reliability consequences to be equal to that of a major LOC on a service.

Major Risk Event – Financial Consequence

Using the subset of PHMSA data described above in “Outcome 1: Major, Consequence – Safety,” PG&E used PHMSA industry data to estimate the financial consequences associated a LOC on a main, service, or riser for low and high population densities.

Minor Risk Event – Reliability Consequence

PG&E estimated the reliability consequences of a minor cross bore event to be similar in magnitude to a minor LOC on a service asset. As such, PG&E aligned the minor cross bore reliability consequences to be equal to that of a minor LOC on a service.

Minor Risk Event – Financial Consequence

PG&E estimated the financial costs associated with a minor LOC by using the estimated PG&E costs associated with a cross bore repair.

Table 2-5 shows the consequences of the risk event. Model attributes are discussed in Exhibit (PG&E-2), Chapter 2.

TABLE 2-5
RISK EVENT CONSEQUENCES

Consequences

	CoRE	%Freq	%Risk	Freq	Natural Units Per Event			Monetized Levels of a Consequence Per Event (2023 $M/event)			CoRE (risk-adjusted 2023 $M)			Natural Units per Year			Expected Loss per Year (2023 $M/yr)			Attribute Risk Score (risk-adjusted 2023 $M/yr)		
					Safety	Gas Reliability	Financial	Safety	Gas Reliability	Financial	Safety	Gas Reliability	Financial	Safety	Gas Reliability	Financial	Safety	Gas Reliability	Financial	Safety	Gas Reliability	Financial
					EF/event	#cust/event	$M/event							EF/yr	#cust/yr	$M/yr						
Minor - Equipment Failure	0.0	56%	19%	15,959	-	0.03	0.0012	-	0.00	0.00	-	0.00	0.00	-	462.33	19.17	-	0.73	19.17	-	0.73	19.17
Minor - Corrosion	0.0	14%	17%	4,038	-	0.16	0.0043	-	0.00	0.00	-	0.00	0.00	-	635.01	17.41	-	1.00	17.41	-	1.00	17.41
Minor - Incorrect Operation	0.0	12%	17%	3,424	-	0.20	0.0049	-	0.00	0.00	-	0.00	0.00	-	667.94	16.61	-	1.05	16.61	-	1.05	16.61
Minor - Excavation Damage	0	6%	9%	1,778	-	0.21	0.0049	-	0.00	0.00	-	0.00	0.00	-	366.66	8.69	-	0.58	8.69	-	0.58	8.69
Minor - Material/Weld Fail	0.00	6%	7%	1,615	-	0.19	0.0045	-	0.00	0.00	-	0.00	0.00	-	312.30	7.26	-	0.49	7.26	-	0.49	7.26
Major - Incorrect Operation	13.38	0%	7%	0.6	0.56	538.46	0.8028	8.58	0.85	0.80	10.80	1.61	0.97	0.32	308.30	0.46	4.91	0.48	0.46	6.19	0.92	0.56
Major - Corrosion	7.17	0%	4%	0.6	0.27	547.73	0.7445	4.16	0.86	0.74	4.65	1.64	0.88	0.17	335.44	0.46	2.55	0.53	0.46	2.85	1.00	0.54
Major - Natural Forces	27.29	0%	4%	0.14	0.81	580.99	0.7431	12.38	0.91	0.74	24.68	1.73	0.87	0.11	81.15	0.10	1.73	0.13	0.10	3.45	0.24	0.12
Minor - Natural Forces	0.01	2%	3%	658	-	0.20	0.0049	-	0.00	0.00	-	0.00	0.00	-	128.39	3.20	-	0.20	3.20	-	0.20	3.20
Minor - Other	0.00	2%	3%	678	-	0.19	0.0046	-	0.00	0.00	-	0.00	0.00	-	128.72	3.12	-	0.20	3.12	-	0.20	3.12
Major - Excavation Damage	7.06	0%	3%	0.5	0.24	497.33	0.8732	3.62	0.78	0.87	4.50	1.48	1.08	0.11	229.64	0.40	1.67	0.36	0.40	2.08	0.68	0.50
Major - Equipment Failure	6.53	0%	2%	0.3	0.23	658.64	0.6025	3.51	1.03	0.60	3.89	2.00	0.64	0.07	210.33	0.19	1.12	0.33	0.19	1.24	0.64	0.21
Major - Material/Weld Fail	9.46	0%	2%	0.2	0.37	410.85	0.9888	5.68	0.64	0.99	6.97	1.22	1.27	0.08	84.85	0.20	1.17	0.13	0.20	1.44	0.25	0.26
Major - Other	10.89	0%	1%	0.09	0.44	471.17	0.8973	6.73	0.74	0.90	8.37	1.40	1.12	0.04	43.67	0.08	0.62	0.07	0.08	0.78	0.13	0.10
Minor - Seismic	0.01	0%	1%	84	-	4.55	0.0047	-	0.01	0.00	-	0.01	0.00	-	381.20	0.39	-	0.60	0.39	-	0.60	0.39
Minor - Other Outside Force	0.00	2%	1%	488	-	0.04	0.0013	-	0.00	0.00	-	0.00	0.00	-	19.05	0.63	-	0.03	0.63	-	0.03	0.63
Major - Seismic	24.66	0%	1%	0.02	0.73	933.34	0.9303	11.15	1.47	0.93	21.78	1.90	0.97	0.02	21.00	0.02	0.25	0.03	0.02	0.49	0.04	0.02
Major - Crossbore	12.05	0%	0%	0.03	0.65	3.37	0.5654	9.93	0.01	0.57	11.45	0.01	0.60	0.02	0.09	0.01	0.25	0.00	0.01	0.29	0.00	0.02
Major - Other Outside Force	8.48	0%	0%	0.04	0.36	216.10	0.8719	5.45	0.34	0.87	6.73	0.64	1.11	0.01	7.80	0.03	0.20	0.01	0.03	0.24	0.02	0.04
Minor - Crossbore	0.02	0%	0%	0.9	-	1.98	0.0130	-	0.00	0.01	-	0.00	0.01	-	1.82	0.01	-	0.00	0.01	-	0.00	0.01
Aggregated	0.00	100%	100%	28,725.7	0.00003	0.15	0.0027	0.000504	0.00024	0.00273	0.00066	0.00031	0.00275	0.95	4,425.68	78.47	14.48	6.95	78.47	19.04	8.81	78.87

C. 2023-2026 Control and Mitigation Plan

Tables 2-6 and 2-7 list all the controls and mitigations PG&E included in its 2020 RAMP, 2023 GRC, and 2024 RAMP (2024-2026 and 2027-2030). The tables provide a view as to those controls and mitigations that are ongoing, those that are no longer in place, and new mitigations. In the following sections, PG&E describes the controls and mitigations in place during the 2023-2026 period and then discusses new mitigations and/or significant changes to mitigations and/or controls during the 2027-2030 period.

TABLE 2-6
CONTROLS SUMMARY

Line No.	Control Number and Name[a]	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2023-2026)	2024 RAMP (2027-2030)
1	C1 – Corrective Maintenance	X	Becomes LOCDM-C024		
2	C2 – Corrosion Control	X	Becomes LOCDM-C018		
3	C3 – DIMP Leak Survey	X	Becomes LOCDM-C014		
4	C4 – Leak Management Pilot Control	X	Becomes LOCDM-C014		
5	C5 – Locate and Mark	X	Becomes LOCDM-C017		
6	C6 – Pipeline Replacement Program	X	Becomes LOCDM-M001, LOCDM-M002		
7	C7 – Preventative Maintenance	X	Becomes LOCDM-C023, LOCDM-C027		
8	C8 – Public Awareness Program	X			
9	C9 – Quality Assurance/Quality Management	X			
10	C10 – Training	X			
11	C11 – Cross Bore Prevention Program	X	Becomes LOCDM-M006		
12	C12 – DIMP Program	X	Becomes LOCDM-C011		
13	LOCDM-C001 – Meter Protection		X	X	X
14	LOCDM-C002 – Improve System Reliability – Gas Main		X	X	X
15	LOCDM-C003 – Improve System Reliability – Gas Services		X	X	X
16	LOCDM-C004 – Improve System Reliability – Gas Valves		X	X	X
17	LOCDM-C005 – Improve System Reliability – Gas Other Equipment		X	X	X
18	LOCDM-C006 – Improve System Reliability – Cut-Off Idle Gas Services		X	X	X
19	LOCDM-C007 – Improve ReM/R/V		X	X	X
20	LOCDM-C008 – Major Event – Distribution Gas		X	X	X
21	LOCDM-C009 – Encroachment Program		X	X	X

TABLE 2-6
CONTROLS SUMMARY
(CONTINUED)

Line No.	Control Number and Name[(a)]	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2023-2026)	2024 RAMP (2027-2030)
22	LOCDM-C010 – Tee Cap Replacement Program		X	X	X
23	LOCDM-C011 – DIMP Emergent Work		X	X	X
24	LOCDM-C012 – Plastics Program		X	X	X
25	LOCDM-C013 – Training, Gas Qualifications		X		
26	LOCDM-C014 – Distribution Leak Management		X	X	X
27	LOCDM-C015 – Gas Distribution Control Center Operations		X	X	X
28	LOCDM-C016 – Gas R&D and Deployment		X		
29	LOCDM-C017 – Locate and Mark - Distribution		X	X	X
30	LOCDM-C018 – Distribution Corrosion Control Program		X	X	X
31	LOCDM-C019 – Casings		X	X	X
32	LOCDM-C020 – Atmospheric Corrosion, Mains and Services		X	X	X
33	LOCDM-C021 – DIMP Program Management		X		
34	LOCDM-C022 – Electrically Connected Isolated Steel Services		X	X	
35	LOCDM-C023 – Preventive Maintenance Gas Services		X	X	X
36	LOCDM-C024 – Corrective Maintenance, Gas, Main Valve		X	X	X
37	LOCDM-C025 – Dig-In Reduction Team		X	X	X
38	LOCDM-C026 – Maintenance, Preventative, Gas Valves		X	X	X
39	LOCDM-C027 – Preventive Maintenance Gas Mains		X	X	X
40	LOCDM-C028 – Training Development		X		
41	LOCDM-C029 – Unprotected Steel Main Evaluation		X		

(a) Controls included in the 2020 RAMP are labeled with “(2020 RAMP)” to distinguish between Control Numbers used in the 2020 RAMP Report and Control Numbers used in the 2023 GRC and 2024 RAMP.

TABLE 2-7
MITIGATIONS SUMMARY

Line No.	Mitigation Number and Name	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2023-2026)	2024 RAMP (2027-2030)
1	M2 – New Valve Installations	X	Becomes LOCDM-M004		
2	M3 – Enhanced CP Survey and Unprotected Main Evaluation	X	Becomes LOCDM-M003		
3	M4 – Electrically-Connected Isolated Steel Service (ECISS) Program	X	Becomes LOCDM-C022		
4	M5 – Pipeline Replacement Program (Steel)	X	Becomes LOCDM-M001		
5	M6 – Pipeline Replacement Program (Plastic)	X	Becomes LOCDM-M002		
6	M7 – Cross Bore Legacy Inspection Program	X	Becomes LOCDM-M006		
7	M9 – Mechanical Fitting Replacement Program	X	Becomes LOCDM-M005		
8	LOCDM-M001 – Pipeline Replacement Program (Steel)		X	X	X
9	LOCDM-M002 – Pipeline Replacement Program (Plastic)		X	X	X
10	LOCDM-M003 – Enhanced CP Survey and Unprotected Main Evaluation		X	X	
11	LOCDM-M004 – New Valve Installations		X	X	X
12	LOCDM-M005 – Fitting Mitigation Program		X	X	
13	LOCDM-M006 – Cross Bore Program		X	X	X

(a) Mitigations included in the 2020 RAMP does not start with LOCDM, distinguishing between Mitigation Numbers used in the 2020 RAMP Report and Mitigation Numbers used in the 2023 GRC and 2024 RAMP.

1. Controls

- LOCDM-C001 – Meter Protection: The purpose of the Meter Protection Program is to protect meters and risers that are vulnerable to vehicular damage, and to install service valves where existing service valves are inaccessible. Preventing damage from vehicles is required in accordance with 49 CFR, Section 192.353. Meter protection is accomplished through relocation of the meter set or installing a protection bollard.
- LOCDM-C002 – Improve System Reliability – Gas Main: The purpose of the Reliability Main Replacement Program is to focus on the replacement of gas facilities (mains and services) to improve safety, reliability and maintain compliance with pipeline regulations. This program covers pipe that does not qualify for replacement under the Steel Pipeline Replacement Program or Plastic Pipe Replacement Program.
- LOCDM-C003 – Improve System Reliability – Gas Services: The purpose of the Reliability Service Replacement Program is to proactively replace services to improve system safety and maintain compliance with pipeline regulations. Examples of reliability service replacements are shallow services; corroded risers; bent risers and unsafe meter locations. Additionally, starting in 2023, copper service replacements will be replaced as part of the Reliability Service Replacement Program.
- LOCDM-C004 – Improve System Reliability – Gas Valves: The purpose of the Valve Programs is to replace existing gas valves greater than or equal to two inches in diameter when required, including when leaking or when they can no longer be safely operated. These valves allow PG&E to quickly depressurize a pipeline section for emergency reasons while minimizing the number of impacted customers.
- LOCDM-C005 – Improve System Reliability – Gas Other Equipment: The purpose of the Other Equipment program is to replace, install, or deactivate facilities that do not fall under the other reliability programs. Examples of this work include the replacement or installation of permanent electronic pressure recorders used to monitor distribution system pressures and the deactivation-only jobs of CP system rectifiers.

- LOCDM-C006 – Improve System Reliability – Cut-Off Idle Gas Services: The purpose of the Cut-Off Idle Gas Services program is to support the removal of gas service stubs that do not have a future use or gas services that are idle and are required to be cut off. Idle services are defined as services that no longer provide gas to customers. The primary risk with stubs or idle services is exposure to excavation damage or external forces.
- LOCDM-C007 – Deactivation Program: The purpose of the Deactivation Program is to deactivate distribution mains and valves that are no longer required to operate the gas distribution system.
- LOCDM-C008 – Major Event - Distribution Gas: The purpose of the Major Event – Distribution Gas program is to respond and provide maintenance and construction support during any major event, such as: fire, storm, earthquakes, etc.
- LOCDM-C009 – Encroachment Program: The purpose of the Encroachment Program is to identify and correct locations where customers or third parties have built over PG&E gas distribution facilities. Encroachments can create unsafe conditions for the public or interfere with PG&E's ability to perform inspections and maintenance.
- LOCDM-C010 – Tee Cap Replacement Program: The purpose of the Tee Cap Replacement Program is to proactively replace plastic tee caps in historically leak-prone locations.
- LOCDM-C011 – DIMP Emergent Work: The purpose of the DIMP Emergent Work program is to support investigation work into gas distribution events and risks and to perform risk mitigations as prescribed to address outputs from the DIMP Operational risk model process.
- LOCDM-C012 – Plastics Program (Foundational): Refer to Section C.3 Foundational Activities for description.
- LOCDM-C013 – Training, Gas Qualifications (Foundational): Refer to Section C.3 Foundational Activities for description.
- LOCDM-C014 – Distribution Leak Management: The purpose of the Distribution Leak Management Program is to conduct periodic leak surveys on PG&E's gas distribution system for the presence of gas

leaks in accordance with pipeline safety regulations. The frequency is determined by code. Identified leaks are graded as: Grade 1 (immediate repair required); Grade 2 (repair to be completed within 15 months); and Grade 3 (monitor and resurvey annually or no later than 15 months). The distribution leak management program includes the mitigation, repair, of the main or service leak.

- LOCDM-C015 – Gas Distribution Control Center Operations (Foundational): Refer to Section C.3 Foundational Activities for description.
- LOCDM-C017 – Locate and Mark - Distribution: The purpose of the Locate and Mark Program is to provide the physical location for PG&E's underground gas distribution assets for PG&E crews and contractors, along with third parties who plan to excavate near those assets. The program also includes the standby process where a PG&E field employee monitors excavation activity in a watch and protect capacity to prevent damage to PG&E facilities.
- LOCDM-C018 – Distribution Corrosion Control Program: The purpose of the Distribution Corrosion Control Program is to address gas distribution assets that may be at risk for corrosion threats. For the purposes of this chapter, this control is focused on the CP Program, which is a method of protecting against external corrosion. Mitigations include maintaining or replacing rectifiers, troubleshooting cathodic protection areas (CPA), and installing anodes.
- LOCDM-C019 – Casings: The purpose of the Casings Program is to address gas distribution casings identified as being contacted. The contacted casing will be mitigated in the manner that is most appropriate and cost effective. Distribution casing mitigation generally involves replacing the cased main with new pipe and abandoning the casing whenever possible. Additionally, many casings on the gas distribution system do not have the facilities necessary to complete initial testing activities including using the testing without leads process; and thus, require new casing test station to be installed for initial and future monitoring.

- LOCDM-C020 – Atmospheric Corrosion, Mains and Services: The purpose of the Distribution Atmospheric Corrosion Inspection and Repair program is to conduct regulatorily required atmospheric corrosion inspection, identification and control on metallic gas piping and equipment (meters) exposed to the atmosphere.
- LOCDM-C021 – DIMP Program Management: The purpose of DIMP Program Management is to perform risk mitigations and investigative work into gas distribution events and risks. This program was merged into the Operational Management and Support (OM/OS), which reflects costs associated with personnel that supervise, manage and/or support the Gas Distribution employees that perform work that are charged to orders.
- LOCDM-C022 – Electrically-Connected Isolated Steel Services: The purpose of the Electrically-Connected Isolated Steel Services program is to identify isolated steel pipe segments that are electrically connected with other isolated steel segments via locate wire and cathodically protect them as a group. Additionally, this program includes verification of follow up remediation, CPA map updates, SAP monitoring schedule updates, and geographic information system updates.
- LOCDM-C023 – Preventive Maintenance Gas Services: The purpose of the preventive maintenance gas services program is to perform non-leak related maintenance on services, such as lowering shallow pipe and restoring adequate cover over the pipe.
- LOCDM-C024 – Corrective Maintenance, Gas, Main Valve: The purpose of the distribution valve corrective program is to repair valves that may be needed for the safe operation of the distribution system. In cases of emergencies that result in the release of gas, these valves can be operated to isolate the system and stop the release of gas. Activities involved in valve repair include replacing or repairing broken valve components (seals, bolts, and extensions), repairing valve enclosures or performing any other corrective maintenance on an inoperable valve.
- LOCDM-C025 – Dig-In Reduction Team (Foundational): Refer to Section C.3 Foundational Activities for description.

- LOCDM-C026 – Maintenance, Preventative, Gas Valves: The purpose of the distribution valve corrective program is to maintain valves that may be needed for the safe operation of the distribution system. Most distribution valves are installed below ground and their maintenance can include cleaning out the valve box, lubricating the valve, flushing the valve, and checking the full or partial operation outside the regulator stations.
- LOCDM-C027 – Preventive Maintenance Gas Mains: The purpose of the preventive maintenance gas mains program is to perform non-leak related maintenance on mains, such as repairing pipe supports for above ground mains or lowering shallow mains and restoring adequate cover over the pipe.

2. Mitigations

- LOCDM-M001 – Pipeline Replacement Program (Steel): The purpose of the Pipeline Replacement Program (Steel) program is to focus on deactivation of pre-1941 steel pipe. When mains and services are deactivated, they are replaced with plastic or steel materials. This program prioritizes pipe segments based on the relative risk of each pipe segment. The risk ranking is based on a methodology that considers pipe age, leak history, CP, coating, seismic activities, and population proximity. PG&E may also include post-1940 higher risk steel projects based on risk modelling.
- LOCDM-M002 – Pipeline Replacement Program (Plastic): The purpose of the Pipeline Replacement Program (Plastic) is to mitigate risks associated with leaks on plastic pipe installed before 1985 with Aldyl-A plastic and similar plastic materials. The Plastic Pipe Replacement Program prioritizes plastic main replacement projects based on the relative risk of each pipe segment. The risk ranking is based on a methodology that considers leak history, pipe age, material type, ground temperature, diameter, operating pressure, and population proximity.
- LOCDM-M003 – Enhanced CP Survey and Unprotected Main Evaluation: The purpose of the Enhanced CP Survey and Unprotected Main Evaluation is to identify the location of all steel main and services

in the system, assure that they are cathodically protected, assure that they are in SAP, and properly monitored.

- LOCDM-M004 – New Valve Installations: The purpose of the New Valve Program is to install valves to reduce the size of emergency shutdown zones and improve PG&E's ability to isolate the gas system in the event a gas emergency.
- LOCDM-M005 – Fitting Mitigation Program: The purpose of the Fitting Mitigation Program is to proactively mitigate fittings with observed integrity issues and a high failure rate due to manufacturing defects.
- LOCDM-M006 – Cross Bore Program: The purpose of the Cross Bore Program is to inspect, identify, and remediate cross bores on the gas distribution system that were installed using trenchless technology. This program uses video equipment to inspect storm drain systems and wastewater mains and laterals for potential cross bore situations and then repair any cross bores identified by the inspections. Additionally, there is a public outreach program that provides safety information to PG&E customers, sewer districts, and public works agencies.

TABLE 2-8
PLANNED MITIGATIONS 2024-2026

			Planned Units of Work				
Line No.	Mitigation ID	Mitigation Name	Unit of Measurement[(a)]	2024	2025	2026	Total
1	LOCDM-M001	Pipeline Replacement Program (Steel)	Feet of main	96,324	127,825	129,839	353,988
2	LOCDM-M002	Pipeline Replacement Program (Plastic)	Feet of main	562,802	733,920	733,920	2,030,642
3	LOCDM-M003	Enhanced CP Survey and Unprotected Main Evaluation	Miles of remediation work	43	43	5	91
4	LOCDM-M004	New Valve Installations	# of valves installed	74	98	102	274
5	LOCDM-M006	Cross Bore Program[(b)]	# of inspections	750	1,367	1,830	3,947

(a) The units of work are presented as used in the RAMP model because the model requires that units of work are standardized. These may differ in some instances from “rate case” units – the units referred to in PG&E’s GRC or other proceedings.

(b) PG&E expects to perform a combination of unable to access (UTA) and non-UTA inspections. The number of inspections will be determined based on availability of and access to inspection sites.
For additional details see Exhibit (PG&E-3), WP GO-LOCDM-F.

The estimated costs for the mitigation work planned for the 2024-2026 period are shown in Tables 2-9 and 2-10 below.

TABLE 2-9
MITIGATION COSTS ESTIMATES
2024-2026 EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Mitigation ID	Mitigation Name	2024	2025	2026	Total
1	LOCDM-M003	Enhanced CP Survey and Unprotected Main Evaluation	$4,213	$4,129	$4,046	$12,388
2	LOCDM-M006	Cross Bore Program	4,452	7,306	8,798	20,555
3		Total	$8,665	$11,434	$12,844	$32,943

Notes:
For additional details see Exhibit (PG&E-3), WP GO-LOCDM-F.
The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030.
See Exhibit (PG&E-1), Chapter 1, Section D.3.

TABLE 2-10
MITIGATION COST ESTIMATES
2024-2026 CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Mitigation ID	Mitigation Name	2024	2025	2026	Total
1	LOCDM-M001	Pipeline Replacement Program (Steel)	$104,291	$124,558	$115,988	$344,837
2	LOCDM-M002	Pipeline Replacement Program (Plastic)	431,005	514,761	479,343	1,425,109
3	LOCDM-M004	New Valve Installations	5,467	6,529	6,080	18,076
4		Total	$540,764	$645,848	$601,411	$1,788,023

Notes:
For additional details see Exhibit (PG&E-3), WP GO-LOCDM-F.
The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030.
See Exhibit (PG&E-1), Chapter 1, Section D.3.

3. Foundational Activities

As discussed in Exhibit (PG&E-2), Chapter 2, foundational activities are programs that enable two or more control or mitigation programs but do not directly reduce the consequences or the likelihood of risk events.

Table 2-11 describes foundational activities that meet this definition and includes (1) information on the control or mitigation programs enabled and (2) the foundational activity program costs on a Net Present Value (NPV) basis that are included in CBR calculations for enabled control or mitigation programs.

- LOCDM-C012 – Plastics Program: The purpose of the Plastics Program is to provide oversight in selecting plastic materials and installation methods for PG&E's gas distribution system.
- LOCDM-C013 – Training, Gas Qualifications: The purpose of the Training, Gas Qualifications is to provide Gas Field employees with Operator Qualifications. PG&E's Gas Qualifications Department maintains and implements qualification programs covering welding, plastic pipe joining, and operator qualifications pursuant to federal and state regulations and industry best practices. PG&E requires that all employees, contractors, and third party installers of pipelines be appropriately trained and possess all requisite qualifications to perform tasks on pipeline facilities. A qualified operator has the expertise to complete work correctly and is part of the team that helps PG&E meet its commitment to public and employee safety.
- LOCDM-C015 – Gas Distribution Control Center Operations: The purpose of the Gas Distribution Control Center Operations is to better communicate, share information, and monitor the gas distribution system to provide superior emergency response coordination (i.e., abnormal conditions).
- LOCDM-C025 – Dig-In Reduction Team: The purpose of the Dig-In Reduction Team is to conduct investigations related to excavation damage to PG&E distribution gas facilities, and to work closely with PG&E personnel and respond to referrals from those employees when they observe excavations potentially not in compliance with the requirements of California Government Code Section 4216.

TABLE 2-11
FOUNDATIONAL ACTIVITIES

Line No.	Foundational Activity ID[(a)]	Foundational Activity Name	Foundational Activity Description	Enabled Control and Mitigation IDs[(a)]	2027-2030 Millions of Dollars (NPV)[(b)]
1	LOCDM-C012	Plastics Program	See description above	LOCDM-C010, LOCDM-M005, LOCDM-M007	$0.79
2	LOCDM-C013	Training, Gas Qualifications	See description above	LOCDM-C002, LOCDM-C003, LOCDM-C004, LOCDM-C006, LOCDM-C007, LOCDM-C008, LOCDM-C009, LOCDM-C010, LOCDM-C011, LOCDM-C014, LOCDM-C017, LOCDM-C018, LOCDM-C019, LOCDM-C020, LOCDM-C023, LOCDM-C024, LOCDM-C026, LOCDM-C027, LOCDM-M001, LOCDM-M002, LOCDM-M003, LOCDM-M004, LOCDM-M005, LOCDM-M007 DUNGD-C016, PCEEE-C001, LRGOP-C013	2.92
3	LOCDM-C015	Gas Distribution Control Center Operations	See description above	LOCDM-C002, LOCDM-C004, LOCDM-C008, LOCDM-C009, LOCDM-C014, LOCDM-C018, LOCDM-C019, LOCDM-C020, LOCDM-C024, LOCDM-C026, LOCDM-C027, LOCDM-M001, LOCDM-M002, LOCDM-M004, LOCDM-M006, LRGOP-C013	23.57
4	LOCDM-C025	Dig-In Reduction Team	See description above	DUNGD-C016, PCEEE-C001, LOCDM-C017	8.36
5			Total		$35.65

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

(b) NPV uses a base year of 2023.

Notes:

For additional details see Exhibit (PG&E-3), WP GO-LOCDM-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

D. 2027-2030 Proposed Control and Mitigation Plan

1. Changes to Controls

PG&E will continue controls C001 through C020 and C023 – C027 in 2027–2030. C021 – DIMP Program Management has been integrated into OM/OS, reflecting the fact that the costs associated with personnel that supervise, manage, and/or support the Gas Distribution employees that perform work that are charged to orders. C022 – Electrically Connected Isolated Steel Services is forecast to complete by the end of 2026. The proposed volume of work for each control is shown in Table 2-13 below.

Table 2-12 below shows the cost estimates, risk reduction values and CBRs for the control programs planned for the 2027-2030 period.

TABLE 2-12
CONTROLS COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[b]			
Line No.	Control ID [a]	Control Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[c] [C]/([A]+[B])
1	LOCDM-C001	Meter Protection	$4,712	$4,785	$4,870	$4,971	$18.7	-	$0.1	<0.1
2	LOCDM-C002	Improve System Reliability – Gas Main	58,330	59,236	60,291	61,542	231.4	3.2	1.8	<0.1
3	LOCDM-C003	Improve System Reliability – Gas Services	9,142	9,284	9,449	9,645	36.3	0.0	0.2	<0.1
4	LOCDM-C004	Improve System Reliability – Gas Valves	7,512	7,628	7,764	7,925	29.8	0.4	12.5	0.4
5	LOCDM-C005	Improve System Reliability – Gas Other Equipment	1,077	1,094	1,113	1,136	4.3	-	0.0	<0.1
6	LOCDM-C006	Improve System Reliability – Cut-Off Idle Gas Services	4,713	4,786	4,872	4,973	18.7	0.0	0.1	<0.1
7	LOCDM-C007	Improve ReM/R/V	6,378	6,477	6,593	6,729	25.3	0.0	0.9	<0.1
8	LOCDM-C008, LRGOP-C013	Major Event – Distribution Gas	460	451	442	433	1.2	0.0	7.8	6.2
9	LOCDM-C009	Encroachment Program	24,451	24,796	25,201	25,685	95.7	1.3	0.4	<0.1
10	LOCDM-C010	Tee Cap Replacement Program	1,694	1,660	1,627	1,594	4.6	0.8	16.9	3.2
11	LOCDM-C011	DIMP Emergent Work	1,908	1,870	1,832	1,796	5.1	0.0	0.1	<0.1
12	LOCDM-C014	Distribution Leak Management	204,615	201,883	199,314	196,940	598.9	8.3	44.1	0.1
13	DUNGD-C016, PCEEE-C001, LOCDM-C017	Locate and Mark – Distribution[c]	85,971	84,252	82,567	80,916	231.1	8.5	113.3	0.5
14	LOCDM-C018	Distribution Corrosion Control Program	43,646	43,421	43,253	43,155	140.6	1.9	201.1	1.4
15	LOCDM-C019	Casings	5,702	5,687	5,680	5,683	18.9	0.3	0.0	<0.1
16	LOCDM-C020	Atmospheric Corrosion, Mains and Services	11,291	11,065	10,843	10,627	30.3	0.4	0.2	<0.1
17	LOCDM-C023	Preventive Maintenance Gas Services	1,896	1,858	1,821	1,784	5.1	0.0	0.1	<0.1
18	LOCDM-C024	Corrective Maintenance, Gas, Main Valve	519	508	498	488	1.4	0.0	0.1	0.1
19	LOCDM-C026	Maintenance, Preventative, Gas Valves	1,971	1,931	1,893	1,855	5.3	0.1	16.7	3.1
20	LOCDM-C027	Preventive Maintenance Gas Mains	1,896	1,858	1,821	1,784	5.1	0.1	0.2	<0.1
21		Total	$477,881	$474,530	$471,742	$469,661				

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

(b) NPV uses a base year of 2023.

(c) CBR calculations include allocated Foundational Activity Program costs.

For additional details see Exhibit (PG&E-3), WP GO-LOCDM-F.
The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

2. Changes to Mitigations

PG&E will continue mitigations M001, M002, M004, and M006 in 2027-2030. LOCDM M003 – Enhanced CP Survey and Unprotected Main is forecast to complete by the end of 2026. Additionally, LOCDM-M005 – Fitting Mitigation Program is not forecast to continue in 2027-2030. The proposed volume of work for each mitigation is shown in Table 2-13 below.

TABLE 2-13
PLANNED MITIGATIONS 2027-2030

			Planned Units of Work					
Line No.	Mitigation ID.	Mitigation Name	Unit of Measurement[(a)]	2027	2028	2029	2030	Total
1	LOCDM-M001	Pipeline Replacement Program (Steel)	Feet of main	134,741	139,628	145,014	151,043	570,426
2	LOCDM-M002	Pipeline Replacement Program (Plastic)	Feet of main	761,636	789,261	819,706	853,786	3,224,389
3	LOCDM-M004	New Valve Installations	# of valves installed	105	109	113	118	446
4	LOCDM-M006	Cross Bore Program[(b)]	# of inspections	1,838	1,838	12,732	13,897	30,304

(a) The units of work are presented as used in the RAMP model because the model requires that units of work are standardized. These may differ in some instances from "rate case" units – the units referred to in PG&E's GRC or other proceedings.

(b) PG&E expects to perform a combination of UTA and non-UTA inspections. The number of inspections will be determined based on availability of and access to inspection sites.
For additional details see Exhibit (PG&E-3), WP GO-LOCDM-F.

TABLE 2-14
MITIGATION COST ESTIMATES, RISK REDUCTION, CBR, AND FACTORS AFFECTING SELECTION
2027-2030 EXPENSE

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[a]				
Line No.	Mitigation ID	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[b] [C]/([A]+[B])	Factors Affecting Selection
1	LOCDM-M006	Cross Bore Program	$8,660	$8,486	$8,317	$8,150	$23.3	$0.3	$0.3	<0.1	Risk Tolerance
2		Total	$8,660	$8,486	$8,317	$8,150					

(a) NPV uses a base year of 2023.

(b) CBR calculations include allocated Foundational Activity Program costs.

Note:

For additional details see Exhibit (PG&E-3), WP GO-LOCDM-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

TABLE 2-15
MITIGATION COST ESTIMATES, RISK REDUCTION, CBR, AND FACTORS AFFECTING SELECTION
2027-2030 CAPITAL

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[(a)]				
Line No.	Mitigation ID	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[(b)] [C]/([A]+[B])	Factors Affecting Selection
1	LOCDM-M0 01	Pipeline Replacement Program (Steel)	$117,959	$119,793	$121,925	$124,455	$467.9	$6.5	$35.2	0.1	Risk Tolerance
2	LOCDM-M0 02	Pipeline Replacement Program (Plastic)	487,496	495,074	503,888	514,341	1,933.6	26.7	86.3	<0.1	Compliance, Risk Tolerance, Modeling Limitations, Operational and Execution Considerations
3	LOCDM-M0 04	New Valve Installations	6,181	6,277	6,389	6,521	24.5	0.3	9.8	0.4	Compliance, Risk Tolerance, Modeling Limitations, Operational and Execution Considerations
4		Total	$611,636	$621,144	$632,202	$645,317					

(a) NPV uses a base year of 2023.

(b) CBR calculations include allocated Foundational Activity Program costs.

Note:

For additional details see Exhibit (PG&E-3), WP GO-LOCDM-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

3. Factors Affecting Mitigation Selection

Tables 2-14 and 2-15 summarize PG&E's proposed mitigations during the 2027-2030 period, including the rationale for selecting the proposed mitigations. The Pipeline Replacement Program (Plastic) mitigation program and the Pipeline Replacement Program (Steel) mitigation program have the highest risk reduction followed by New Valve Installations, respectively. Additional information on the rationale for selecting mitigations is provided below.

- <u>Compliance Requirements</u>: In addition to addressing risk, each mitigation is designed to meet federal and state compliance requirements. PG&E uses an operational risk model compliant with CFR Title 49, Transportation, Part 192—Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards, Subpart P, "Gas Distribution Pipeline Integrity Management," to identify mitigation projects. The output of the model and subsequent analysis leads to the identification of work performed under the mitigation programs to address the LOCDM RAMP risk. Additional sections of federal code[14] require mitigations when certain conditions are met. The following federal-code requirements[15] are applicable to the mitigations programs that address the LOCDM RAMP risk:
  - Each segment of pipeline that becomes unsafe must be replaced, repaired, or removed from service – 49 CFR 192.703;
  - Distribution Line Valves – 49 CFR 192.181;
  - Shallow cover conditions – 49 CFR 192.327;
  - Atmospheric corrosion mitigation requirement – 49 CFR 192.481; and
  - Cathodic protection mitigation requirements – 49 CFR 192.465/469/471/473.

  In addition to these federal requirements, several state and federal regulatory agencies have notified operators through advisories and

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14 CFR Title 49, Transportation, Part 192—Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards.

15 This list provides some but not all applicable regulations.

publications of safety-related warnings pertaining to gas distribution piping and appurtenances. For example, the PHMSA has issued multiple advisories relating to the mitigation program Pipeline Replacement Program (Plastic).[16] Additionally, the CPUC has also published a report related to the Pipeline Replacement Program (Plastic) warning of the potential for catastrophic failure of certain pipe vintages.[17]

Most recently, PHMSA Gas Distribution Pipeline Notice of Proposed Rulemaking (NPRM) (Docket# PHMSA-2021-0046) proposes to revise § 192.1007(b) to clarify that operators must identify the threats posed by specific material types in their pipeline system. The PHMSA NPRM states: "PHMSA expects that, in determining whether a plastic pipe material is a 'historic plastic with known issues' representing a threat to pipeline integrity, operators should consider PHMSA and State regulatory actions and industry technical resources identifying systemic integrity issues on plastic pipe made from particular materials manufactured at particular times or by particular companies, or fabricated and installed pursuant to particular processes…Once the threats are identified under § 192.1007(b), operators are also required to evaluate these risks under § 192.1007(c) and to ensure that risk reduction measures are identified and implemented under § 192.1007(d)."[18]

- Risk Tolerance: The Commission has recognized the need for discussion and clear guidance on Risk Tolerance and has expressed its intention to address this topic in future Phases of the Risk OIR. In the meantime, PG&E's risk mitigation strategies are selected to ensure that safety remains PG&E's top priority even when the quantitative RAMP modelling indicates the costs are higher than the modeled value of risk reduction. All the mitigations for the LOCDM risk are to address the risk

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16 PHMSA's Advisory Bulletins: ADB-99-02 (Oct. 1, 1999); ADB-02-07 (Nov. 26, 2002); and ADB 07-01 (Sept. 6, 2007.

17 CPUC's Hazard Analysis & Mitigation Report on Aldyl-A Polyethylene Gas Pipelines in California (June 11, 2014).

18 PHMSA Gas Distribution Pipeline NPRM (Docket# PHMSA-2021-0046), pp. 54-55.

of catastrophic equipment failure that could result in a serious injury or fatality:

- Cross Bore Program: Cross bores are a concern for gas utility operators nationwide and are identified as presenting a high risk to public and employee safety.[19] While the bow tie analysis shows that cross bore is not a significant driver of the LOC on Gas Distribution Main or Service risk event, the program is a unique mitigation activity that eliminates risk with every cross bore inspection performed. The catastrophic consequences of a cross bore event are difficult to estimate based on the range of scenarios (one or several NG ignitions that could occur), but reasonably could result in personal injury, loss of life, and significant financial outcomes.
- New Valve Program: The New Valve Installations mitigation program is to install new gas valves greater than or equal to two inches in diameter. These valves allow PG&E to quickly depressurize a pipeline section for emergency reasons while minimizing the number of impacted customers. New valves are primarily installed to improve PG&E's ability to isolate the gas system through Emergency Shutdown Zones. Emergency shutdown zones establish geographic areas that can be shut down quickly with minimal impacts to the surrounding system.
- Pipeline Replacement Program (Steel) : This program is focused on deactivating higher risk steel pipe, including pre-1941 steel pipe, and bare or non-cathodically protected steel pipe. When mains and services are deactivated, they are replaced with plastic or steel materials. Additional pipe may be included for construction efficiency and system operational considerations in accordance with internal work procedures. PG&E may also include post-1940 higher risk steel projects based on risk modelling. Although many leaks on steel main and services result in minor LOC events, PG&E needs to

[19] A.21-06-021 GRC 2023, Exhibit (PG&E-3), Chapter 4, p. 4-13, lines 19-21.

replace this pipe over significant time (100+ years) to ensure failures do not proliferate at an end of asset life scenario.

- Pipeline Replacement Program (Plastic) : This program is focused on deactivating pre-1985 Aldyl-A plastic and similar plastic materials. Plastic materials of pre-1985 vintage have a susceptibility to slow crack growth when exposed to stress, such as tree roots, differential settlement, or rock impingement. External stress can cause the initiation and propagation of cracks leading to leaks. The resultant LOC from slow crack growth can result in a rupture which results in an increased probability of a major event. On August 31, 2011, PG&E experienced an Aldyl-A two-inch in-line tee crack on the body of the fitting as a result of slow crack growth resulting in gas migration into a house, ignition, and explosion. PG&E has experienced seven ignitions or explosions associated with pre-1985 Aldyl-A pipe.

- Modeling Limitations: Consideration must be given to mitigation programs with a low CBR score to reflect the benefit to PG&E customers over a length of time beyond the model's purview. For the pipe replacement mitigation programs, the CBR scores do not capture the nonlinear nature of asset failure toward the end of expected useful life. Simply stated, as pipe ages, leaks, and other failures, including catastrophic failure, can be expected to proliferate. Once this escalated failure rate is reached, the situation could not be readily addressed due to excessive costs and the practical inability of the skilled and qualified workforce to perform in a timely manner. These potential future scenarios are not captured in the model, thereby understating the risks and the benefits of these programs.
- Operational and Execution Considerations: PG&E's proactive replacement of plastic distribution pipelines and steel pipe is a prudent risk-informed asset management approach to managing asset risk before the pipelines reach end of life. Absent proactive, steady state, replacement of plastic distribution pipeline, a serious safety, resources, and funding crisis will likely occur in the future. A time will come where the rate of LOC events escalates as the pipe near end-of-life, increasing

the likelihood of catastrophic failure such as a sudden crack failure in plastic pipe. This escalation of failures will exceed the capacity of the skilled and qualified workforce and/or exceed a reasonable cost burden that rate payers are willing to pay over a short period of time to replace, repair, or deactivate the failed assets. While these two pipeline replacement programs have CBR scores less than 1, PG&E believes it is important to continue replacing or deactivating high risk vintage assets as part of a long-term risk reduction approach to avoid the point in which leaks occur at a rate that threatens public safety and exceeds a reasonable cost burden that limits funding in other expense controls and mitigations.

E. Alternative Mitigations Analysis

In addition to the proposed mitigations described in Section E above, PG&E considered alternative mitigations as well. The mitigations described in Section E constitute the Proposed Plan. The Alternative Plans described below consist of a combination of some or all the proposed mitigations along with the alternative mitigation(s). PG&E describes each of the alternative mitigations it considered below and then provides Tables 2-16, 2-17, and 2-18 showing the cost estimates, risk reduction values and CBRs for each of the Alternative Plans.

1. Alternative Plan 1: Electrification

In relation to the Long-Term Gas Planning Proceeding (R.20-01-007), PG&E has considered electrification as an alternative to its Steel and Plastic main pipeline replacement programs. The program would include qualified pipes in the Gas Pipeline Replacement Program (MAT 14A) and Plastic Pipe Replacement Programs (MAT 14D). In this alternative, gas mains and services planned for replacement in these two programs would be deactivated and services converted to all-electric service.

PG&E developed a cost estimate for deactivating pipelines and retrofitting homes based on publicly available cost data. For this analysis, PG&E assumed that pipeline deactivation does not impact gas system hydraulics and there is no additional asset investment to continue serving existing gas customers. The cost estimate also did not account for any PG&E electric infrastructure upgrades and/or reinforcements, which may be needed for the additional loads. PG&E also assumed that the electrification alternative is 100 percent effective at reducing all gas distribution mains and services risk drivers. Due to model limitations, the potential risk to the electric system was not considered in the risk model.

Implementing this alternative involves higher costs compared to just pipe replacements. Additionally, it assumes that all customers will agree to the conversion, i.e., no customers remaining on the segment would still require gas service. PG&E is not currently pursuing this alternative due to regulatory requirements establishing the obligation to serve which requires customers to agree to convert to electric service only. While PG&E is choosing not to implement this program at this time, PG&E will continue to evaluate the feasibility of converting individual projects to electric service on an individual project basis in relation to the Alternative Energy Program (MAT AB#) as discussed in the 2023 GRC decision (D.23-11-069).

TABLE 2-16
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[a]		
Line No.	Mitigation ID	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	LOCDM-A001	Electrification-Steel	$100,193	$103,827	$107,832	$112,316	$409.2	$39.1	0.1
2		Total	$100,193	$103,827	$107,832	$112,316			

(a) NPV uses a base year of 2023.

For additional details see Exhibit (PG&E-3), WP GO-LOCDM-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

TABLE 2-17
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[a]		
Line No.	Mitigation ID	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	LOCDM-A002	Electrification-Plastic	$677,200	$701,762	$728,832	$759,134	$2,766.0	$119.6	<0.1
2		Total	$677,200	$701,762	$728,832	$759,134			

(a) NPV uses a base year of 2023.

Notes:

For additional details see Exhibit (PG&E-3), WP GO-LOCDM-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

2. Alternative Plan 2: Residential Methane Detectors

Installation of Residential methane detectors (RMD) has the potential to avoid the need to perform extensive leak management when responding to a call-out related to a methane detector and address the likelihood of an event turning into a major event by early alert of methane build-up at an inside location. PHMSA's incident data between 2010-2022 (excluding incidents caused by vehicle damage) shows that indoor meter sets had an average of 0.61 injuries or fatalities per incident, whereas outdoor meter sets had an average of 0.21 injuries or fatalities per incident. RMDs alert the public of a life-safety condition resulting from dangerous levels of combustible gas in the air. These devices, like a smoke alarm, alarm with a verbal warning, audibly, and usually include a warning light for visual purposes. The alarm generally uses a detection threshold of 10 percent lower explosive limit (LEL). The LEL is the lowest concentration of NG that will burn in air. Detection thresholds are established by Underwriters Laboratories 1484 and National Fire Protection Association 715 standard. The RMDs can integrate a network interface card to integrate with a Utility's existing advanced meter infrastructure (AMI) network to enable automated alerting of the utility of the developing life-safety condition. With integration to the utility's AMI, the utility can develop automation to enable dispatch of qualified personnel to respond and investigate regardless of if the audible, verbal, and visual alarm are received and acted upon by the public.

PG&E began evaluating use of RMDs in 2023 at inside meter set locations. An inside meter set is defined as a meter set where any above ground PG&E gas asset (including riser) is located inside a building, enclosed by four walls and a roof. This includes unvented cabinets and garages unless there is no door (i.e., carport) or the door is not solid (i.e., a gate).

The scope of work for this alternative would include locations within the following tranches for the LOC on Gas Distribution Main or Service risk:
Riser – Indoor – Steel Installed <1941 – Population Density High; and
Riser – Indoor – Plastic Installed < 1985 – Population Density High

PG&E is not pursuing the deployment of devices to the entire population of locations within the above tranches at this time but will continue to evaluate the results of the pilot program installing RMDs at inside meter set locations to assist in the determination if implementing this mitigation is prudent.

TABLE 2-18
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030

Line No.	Mitigation ID	Mitigation Name	Thousands of Nominal Dollars 2027	2028	2029	2030	Millions of Dollars (NPV)[a] Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	LOCDM-A003	RMDs	$14,945	$14,945	$14,945	$14,945	$41.3	0.4	<0.1
2		Total	$14,945	$14,945	$14,945	$14,945			

(a) NPV uses a base year of 2023.

Notes:

For additional details see Exhibit (PG&E-3), WP GO-LOCDM-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

PACIFIC GAS AND ELECTRIC COMPANY
RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 3
RISK ASSESSMENT AND MITIGATION STRATEGY:
LARGE OVERPRESSURE EVENT
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CHAPTER 3
RISK ASSESSMENT AND MITIGATION STRATEGY: LARGE OVERPRESSURE EVENT DOWNSTREAM OF GAS MEASUREMENT AND CONTROL FACILITY

A. Executive Summary

The Large Overpressure (OP) Event Downstream of Gas Measurement and Control (M&C) Facility risk event (LRGOP) is defined as the failure of a gas M&C facility to perform its pressure control function, resulting in a large OP event downstream. Large OP events have the potential to result in significant impacts to public safety, employee safety, contractor safety as well as property damage, financial losses, and the ability to deliver natural gas to customers. There are two drivers for this risk event: Equipment-Related and Incorrect Operations. A single cross-cutting factor, namely Records and Information Management (RIM), has also been modeled.

Pacific Gas and Electric Company's (PG&E) exposure to this risk consists of over 4,400 transmission and distribution regulator stations and regulator sets in its gas service area. This risk event is expected to occur on the order of six[1] times per year based on 2027 Test Year (TY) Baseline model results. Although 96 percent of the risk event outcomes are "benign" (in that they do not lead to any loss of containment [LOC]), the remaining 4 percent of events that do involve LOC account for over 98 percent of the total risk score. The Equipment-Related driver accounts for 66 percent of the risk, and the Incorrect Operations driver accounts for the remaining 34 percent. The RIM cross-cutting factor is considered a sub-driver to Incorrect Operations and accounts for approximately 3 percent of the risk. The mitigations that PG&E will implement from 2027-2030 are intended to address both drivers for this risk.

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1 This is the number of risk events that the model predicts may occur in 2027 prior to the implementation of any of the 2027-2030 proposed mitigations.

PG&E has identified seven tranches of facilities for this risk. Each tranche represents a group of M&C facilities that can be considered to have a relatively similar risk profile in terms of likelihood and consequences of the risk event. Over 85 percent of the overall 2027 TY Baseline risk score can be attributed to two tranches, namely the Transmission Large Volume Customer (LVC)-Type Facilities and the Transmission Complex Stations.

The large OP risk event has the twelfth-highest 2027 TY Baseline Safety Risk Score ($18.2 million) and the twenty-second-highest 2027 TY Baseline Total Risk Score ($19.2 million) of PG&E's 32 Corporate Risk Register risks. PG&E is proposing a series of controls and mitigations from 2027-2030 to address large OP risk. Current model results indicate that the three mitigation programs that provide the greatest risk reduction are the Gas Transmission (GT) Overpressure Protection Program, the GT Supervisory Control and Data Acquisition (SCADA) Visibility Program, and the Gas Distribution (GD) Overpressure Protection Program.

1. Risk Overview

PG&E's gas M&C assets monitor, measure, and control pressure and flow within the gas transmission and distribution systems. The assets include both gas transmission and distribution regulator and meter stations, regulator sets, and associated equipment. The over 4,400 regulating facilities[2] within the M&C asset family play a key role in system safety and reliability by protecting downstream pipeline assets from pressure excursions.

When gas pressure in a pipeline exceeds the pipeline's maximum allowable operating pressure (MAOP), an OP event is said to have occurred. Gas transmission and distribution regulator stations and regulator sets include a regulating device to control gas pressure and one (primary) overpressure protection (OPP) device that is intended to operate should the regulating device fail. Overpressure events can occur when both the regulating device and the primary OPP device fail to perform their pressure control function and the pressure downstream of the facility rises above the

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[2] The terms "station" and "facility" are used interchangeably throughout this chapter, but these terms may have general or very specific meanings in other PG&E documents, Federal and State codes and regulations, and industry standards and design codes.

MAOP. The degree to which the MAOP is exceeded as described in Table 3-1 determines whether an OP event is considered a “large” OP event (see footnote a).

TABLE 3-1
RISK OVERVIEW

Line No.	Risk name	Large OP Event Downstream of Gas M&C Facility
1	Definition	Failure of a gas M&C facility to perform its pressure control function resulting in a large OP event downstream that can lead to significant impact on public safety, employee safety, contractor safety, property damages, financial losses, and the inability to deliver natural gas to customers.
2	In scope	Large OP Events[a]
3	Out of scope	Other OP Events[b]
4	Data quantification sources	PG&E Large OP Event Data 2014-2022 Pipeline and Hazardous Materials Safety Administration (PHMSA) Reportable Incident Data 2010-2023.

(a) An OP event occurs when gas pressure exceeds the MAOP of the pipeline as determined by California Public Utilities Commission (CPUC or Commission)/Department of Transportation requirements. PG&E uses the below criteria to classify OP events as large OP events:

- High pressure distribution (1 pounds per square inch gauge (psig) ≤ MAOP < 12 psig): Pressure > 150% MAOP;
- High pressure distribution (12 psig ≤ MAOP < 60 psig): Pressure > MAOP + 6 psig;
- Low pressure distribution: Pressure > 16 inches water-column;
- Transmission: Pressure > 110% MAOP or produces a hoop stress of ≥ 75% Specified Minimum Yield Strength (SMYS), whichever is lower (based on 49 Code of Federal Regulations (CFR) 192.201); and
- Customer houseline: A large OP event occurs if one of the thresholds on customer rated equipment is breached, if customer equipment is damaged by excess pressure, or if LOC occurs due to excess pressure.

(b) OP events where the pressure exceeds the MAOP but does not meet any of the criteria in footnote (a).

B. Risk Assessment

1. Background and Evolution

The Large OP Event Downstream of Gas M&C Facility risk event presented in this chapter, Exhibit (PG&E-3), Chapter 3, is the same risk that was presented in Chapter 9 of PG&E’s 2020 Risk Assessment and Mitigation Phase (RAMP) Report. The definition of the risk has not changed; it remains the failure of a gas M&C facility to perform its pressure control function, resulting in a large OP event downstream.

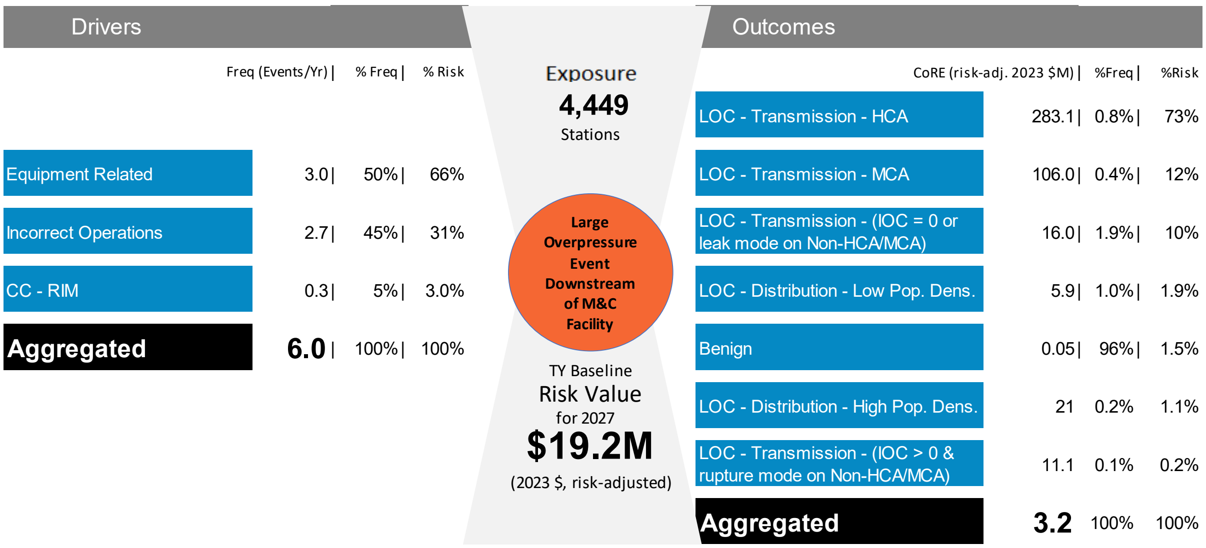
The 2023 General Rate Case (GRC) included several modifications to this risk model compared to the 2020 RAMP. First, the number of tranches for this risk expanded from six to seven as the Transmission Terminals were separated from the Transmission Complex Stations to become their own tranche. Second, the model for this risk in the 2020 RAMP included a tranche for Transmission Large Volume Customer Regulator (LVCR) Sets. In the 2023 GRC this tranche was expanded and renamed to encompass all Transmission LVC-Type Facilities that include regulation equipment. The risk model presented in this chapter contains the same seven tranches presented in the 2023 GRC.

Another modification to this risk model between the 2020 RAMP and the 2023 GRC involved the number of outcomes. This risk as presented in the 2020 RAMP included two types of outcomes, namely large OP events that lead to LOC downstream and those that do not. In the 2023 GRC, the number of outcomes increased to account for different LOC consequences on different types of pipelines downstream of M&C facilities. PG&E has aligned the consequence parameters in this risk model with data utilized for the Loss of Containment on Gas Transmission Pipeline (LOCTM) and Loss of Containment on Gas Distribution Main or Service (LOCDM) risks.

In Decision (D.) 23-12-003, p. 48, Ordering Paragraph 4, the Commission approved PG&E's proposed Transmission Definition change. The analysis presented in this chapter does not incorporate this change. PG&E is in process of analyzing this change and will include any impacts in its 2027 GRC filing.

2. Risk Bow Tie

FIGURE 3-1
RISK BOW TIE



a. Difference from 2020 Risk Bow Tie

There are two main differences in the bow tie for this risk compared to the 2020 RAMP. First, the cross-cutting factors quantified in this risk model have changed since the 2020 RAMP. Additional information is presented on cross-cutting factors in Section 7. Second, the number of outcomes has increased to account for different consequences associated with different downstream pipelines. Whereas the 2020 RAMP included two types of outcomes, namely large OP events that lead to LOC and those that do not, the bow tie in Figure 3-1 shows multiple outcomes associated with different downstream pipeline characteristics. Seven outcomes are included; six outcomes involve LOC (with four on transmission pipe and two on distribution pipe) and one outcome is included in which no LOC occurs.

3. Exposure to Risk

PG&E's gas transmission and distribution systems present inherent safety and reliability risks including the risk of large OP events. PG&E quantifies the exposure to this risk based on the number of M&C regulator stations and regulator sets owned and operated by PG&E. The total exposure used in the model is 4,449 transmission and distribution M&C regulating facilities.

4. Tranches

PG&E has identified seven facility-based tranches for this risk, with four tranches representing transmission facilities and three tranches representing distribution facilities. Each tranche represents a group of M&C stations that have a relatively homogenous risk profile in terms of likelihood and consequence of the risk event, and specific risk likelihood and consequence profiles can be assigned to each tranche. The tranches are described below along with additional background information on PG&E's M&C facility types.

a. Transmission

Transmission Terminals: This tranche includes PG&E's three terminals. These stations function as hubs in the gas transmission system to route gas from the backbone transmission lines to local transmission lines.

Transmission regulator stations function to regulate pressure and flow of gas throughout PG&E's transmission system. Major asset components within these stations include pressure regulation equipment, station valves and actuators, relief valves, meters, process control instrumentation, SCADA equipment, as well as station piping. Since there is considerable variation in the complexity of station equipment and controls, transmission regulator stations are divided into two different tranches, namely Transmission Complex Stations and Transmission Simple Stations.

Transmission Complex Stations: This tranche includes stations that have complex controls and operation including either a Programmable Logic Circuit or Remote Terminal Unit (RTU) to provide control and data transmission.

Transmission Simple Stations: This tranche includes pilot-operated stations that have simple control and operation. Stations within this category may include instrumentation and RTUs, provided they are for monitoring and data transmission purposes only.

Transmission LVC-Type Facilities: Large Volume Customers (LVCs) are those served by a PG&E facility that has the capability of delivering 40,000 standard cubic feet per hour (scfh) or more. The Transmission LVC-Type Facilities tranche includes both LVC Meter (LVCM) Sets with regulation as well as LVCR Sets, which are pressure regulator sets upstream of the typical regulation that occurs at LVCMs.

b. Distribution

PG&E defines distribution district regulator stations as those stations that serve more than one service line (typically hundreds to thousands of customers). These stations typically receive gas from the high-pressure gas transmission system. Approximately 90 percent of these stations regulate gas into local distribution systems at a pressure no higher than 60 psig. The remaining 10 percent of these stations regulate gas into what are called “low-pressure distribution systems” that have operating pressures below 1 psig. PG&E uses two general types of regulators at these stations: “pilot-operated” (Non-high pressure regulator [HPR]-Type) and “spring-operated” (HPR-Type).

- Non-HPR-Type: PG&E refers to pilot-operated regulators as “Non-HPR-Type” regulators. These regulators are larger in size than HPR-Type regulators and are used in district regulator stations serving a large gas demand.
- HPR-Type: PG&E refers to spring-operated regulators as HPR-Type or HPRs. HPRs are relatively small in size, and they are used in facilities serving a small gas demand.

Distribution District Regulator Stations (Non-HPR-Type): This tranche consists of pilot-operated stations that serve two or more service lines and typically serve hundreds to thousands of customers. These stations normally receive gas from the high-pressure transmission pipeline system.

Distribution District Regulator Stations (HPR-Type) and Farm Taps: This tranche consists of spring-operated district regulator stations and farm tap regulator sets. Farm tap regulator sets are spring-operated regulator sets; they serve a single service line that is connected directly from a transmission line or gathering line to serve customers other than an LVC.

Distribution Low-Pressure District Regulator Stations: This tranche consists of the low-pressure district regulator stations that regulate gas pressure into “low-pressure distribution systems” with operating pressures below 1 psig.

The number of facilities in each tranche, the percent of the exposure each tranche represents, and the percent of risk associated with each tranche are provided in Table 3-2 below.

As shown in Table 3-2, the tranche that represents the most risk as predicted by the model is the Transmission LVC-Type Facilities tranche. There are likely multiple factors that are influencing the proportion of risk assigned to this tranche, including the likelihood of these facilities to experience large OP events, the likelihood of those events progressing to LOC, and the consequence parameters assigned to downstream pipe segments. Additional information on these factors is presented in Section 5.

TABLE 3-2
RISK EXPOSURE BY TRANCHE

Line No.	Tranche	Count of Stations	Percent Exposure	Safety Risk Score ($M)	Reliability Risk Score ($M)	Financial Risk Score ($M)	Total Risk Score ($M)	Percent of Risk[a]
1	Transmission Terminals	3	0.1%	$0.156	$0.011	$0.002	$0.169	1%
2	Transmission Complex Stations	82	1.8%	2.412	0.203	0.062	2.677	14%
3	Transmission Simple Stations	261	5.9%	1.222	0.013	0.049	1.285	7%
4	Transmission LVC-Type Facilities	373	8.4%	13.995	0.011	0.381	14.387	75%
5	Distribution District Regulator Stations (Non-HPR-Type)	1,275	28.7%	0.225	0.074	0.107	0.407	2%
6	Distribution District Regulator Stations (HPR-Type) and Farm Taps	2,265	50.9%	0.055	0.024	0.036	0.115	1%
7	Distribution Low-Pressure District Regulator Stations	190	4.3%	0.113	0.010	0.065	0.188	1%
8	Total	4,449	100%	$18.179	$0.346	$0.703	$19.228	100%

(a) Risk is calculated based on frequency and consequence. The Percent of Risk is the contribution from each tranche to the overall risk.

5. Drivers and Associated Frequency

a. Risk Drivers

The risk drivers for PG&E's large OP event risk are based on investigations of large OP events that have occurred at PG&E's M&C facilities. These investigations have yielded causal information and helped define actions that can prevent recurrence. Based on the results of its investigations, PG&E has identified two primary risk drivers for its large OP event risk, namely Equipment-Related and Incorrect Operations. Events associated with incorrect operations are generally a result of human performance, and all other events can be considered equipment-related since they occur due to some kind of pressure regulating equipment failure. These risk drivers align with the American Society of Mechanical Engineers (ASME) B31.8S[3] Standard. The drivers and their frequencies based on PG&E Large OP Event Data from 2014-2022 are discussed below.

D1 – Equipment Related: Equipment-related failures can occur due to equipment age, obsolescence, inadequate maintenance, design issues, or the presence of contaminants such as liquids or debris. Of the 64 large OP events that PG&E has experienced at M&C facilities during the nine-year period between 2014 and 2022, 34 (53 percent) were due to equipment-related failures. These data yield an average of 3.8 equipment-related events per year. After implementing risk mitigations between 2023-2026, the expected 2027 TY Baseline frequency for equipment-related events is 3.0 events per year, accounting for 50 percent of all events.

D2 – Incorrect Operations: Incorrect operations are associated with human performance. Examples include errors in clearance writing or execution, errors in design (e.g., sense line location, oversized regulation, etc.), incorrect installation of equipment, incorrect regulator set points, or work performed by improperly or inadequately trained personnel. Of the 64 large OP events that PG&E has experienced at M&C facilities during the nine-year period between 2014 and 2022,

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[3] The ASME, ASME B31.8S – 2018, "Managing System Integrity of Gas Pipelines."

30 (47 percent) were due to incorrect operations. These data yield an average of 3.3 events due to incorrect operations per year. After implementing risk mitigations between 2023-2026, the expected 2027 TY Baseline frequency for incorrect operations events is 3.0 events per year, accounting for 50 percent of all events.

b. Risk Driver Frequencies

To determine the likelihood with which PG&E may experience a large OP event in each of the tranches, PG&E analyzed its Large OP Event Data from 2014 to 2022 to classify large OP events by station type and risk driver. For this risk event, there are a total of seven tranches and two risk drivers, resulting in 14 different risk event frequencies that are provided as inputs to the model.

c. Outcome Frequencies

Although large OP events have the potential to lead to significant consequences, these consequences are most severe when the event results in LOC on downstream pipeline. Large OP events that do not result in LOC generally result in only financial consequences.

The large OP risk considers seven outcomes that can be classified into two main types, namely those where an LOC occurs and one outcome where it does not. Therefore, the first step is to assess the likelihood of large OP events that do and do not result in LOC downstream, and the risk model requires inputs that represent the proportions of large OP events that can be considered as leading and not leading to LOC.

As stated above in Section 4, the exposure associated with this risk consists of seven tranches. PG&E analyzed its Large OP Event Data from 2014 to 2022 to determine how many large OP events led to losses of containment across the various tranches.

Of the 64 large OP events PG&E experienced at M&C facilities from 2014 to 2022, three resulted in LOC downstream. Two out of the 26 events (eight percent of events) that occurred on Transmission LVC-Type Facilities resulted in LOC. The likelihood of LOC for all other tranches was similarly based on the proportion of large OP events that resulted in LOC during the 2014-2022 time period (1 out of 38 events, or 3 percent).

Once the likelihoods of large OP events resulting in LOC are defined, the next step is to quantify the proportions of those events that occur on pipe with specific properties so that consequences can be more accurately assessed. As stated above, this risk considers seven outcomes, six of which involve LOC. Of these six outcomes involving LOC, four are on transmission pipe and two are on distribution pipe. Based on properties of pipe downstream of transmission and distribution stations, the proportions of LOC events that occur on pipeline in each of the outcomes are determined.

6. Climate Adaptation Vulnerability Assessment Results

PG&E designed the Climate Adaptation Vulnerability Assessment (CAVA) to be consistent with the CPUC's Final Ruling (D.20-08-046) on Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Change Adaptation (Rulemaking 18-04-019). The methodology outlined by D.20-08-046 requires utilities to perform an assessment of all assets, operations, and services that will be impacted by future risks associated with climate change-related changes in temperatures, precipitation and flooding, sea level rise, wildfire, and drought-driven subsidence.

PG&E's CAVA addresses actual or expected climatic impacts on the gas M&C facilities, with a focus on the 2050 decadal time period.[4] The CAVA results do not explicitly consider how climate change will directly impact the likelihood of a large OP event. Instead, the CAVA climate risk findings consider generalized impacts from future climate hazards to gas M&C assets that could have significant consequences for customers, public safety, and the environment.

Key factors in assessing climate change-related risks to M&C facilities include the exposure of the facilities to future climate hazards and the sensitivities of different types of assets at the facilities. The climate hazards

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[4] PG&E's Climate Adaptation Vulnerability Assessment, Section 3.1.2.d Gas Measurement and Control Stations (to be published May 15, 2024).

assessed for the M&C facilities along with the associated climate change risk levels are shown in Table 3-3.

TABLE 3-3
MEASUREMENT & CONTROL CLIMATE ADAPTATION VULNERABILITY ASSESSMENT CLIMATE RISK LEVELS

Line No.	Climate Hazard	Climate Change Risk
1	Temperature	Low (Off-ramped)
2	Flooding/Precipitation	Moderate
3	Sea Level Rise	Low (Off-ramped)
4	Wildfire	Low (Off-ramped)
5	Drought-driven subsidence	Low (Off-ramped)

The climate risk levels shown in Table 3-3 are based off assessment of asset vulnerability to the climate hazard combined with views on the adaptive capacity to these 2050 hazard conditions.

7. Cross-Cutting Factors

A cross-cutting factor is a driver, component of a driver, or a consequence multiplier that impacts multiple risks. PG&E is presenting seven cross-cutting factors in the 2024 RAMP. The cross-cutting factors that impact the Large OP Event Downstream of an M&C Facility risk are shown in Table 3-4 below.

TABLE 3-4
CROSS-CUTTING FACTOR SUMMARY

Line No.	Cross-Cutting Factor	Impacts Likelihood	Impacts Consequence
1	Climate Change	Yes*	No
2	Cyber Attack	Yes*	Yes*
3	Emergency Preparedness and Response	No	Yes*
4	Information Technology Asset Failure	No	Yes*
5	Physical Attack	Yes*	No
6	RIM	Yes	Yes
7	Seismic	No	No

Notes:

Yes The cross-cutting factor has been quantified in the model.

Yes* The cross-cutting factor does influence the baseline risk but has not been quantified in the model, or the cross-cutting factor may influence the baseline risk but further study is needed.

No The cross-cutting factor does not meaningfully influence the baseline risk.

One cross-cutting factor has been modeled as part of the large OP event risk, namely RIM. This cross-cutting factor is considered a sub-driver to Incorrect Operations; it has the potential to influence both the likelihood and consequences associated with this risk.

A description of the cross-cutting factors and the mitigations and controls that PG&E is proposing to mitigate the cross-cutting factors is in Exhibit (PG&E-2), Chapter 3.

8. Consequences

As discussed in Section 5.c, there are seven potential outcomes associated with this risk event. Six of the outcomes involve LOC on downstream pipeline, and one of the outcomes results in no LOC.

- The vast majority of large OP events do not result in LOC. This “benign” outcome is expected to occur 96 percent of the time and accounts for less than 2 percent of the 2027 TY Baseline risk score; and
- Outcomes with LOC are expected to occur 4 percent of the time, and these outcomes account for over 98 percent of the 2027 TY Baseline risk score.

a. Consequences Associated With No LOC

Even though most large OP events that PG&E has experienced have not resulted in LOC, there are still consequences associated with such events. When such an event occurs, PG&E reports the event to regulatory agencies as required and takes specific actions to confirm the safety of the facilities involved, including verification of records, physical inspection, leak testing, and, in some cases, component replacement. Actions also include immediate reduction of operating pressure until the confirmation steps are completed. These activities result in financial consequences associated with this outcome.

b. Consequences Associated With LOC

Of the six outcomes associated with LOC, four are on transmission pipeline and two are on distribution pipeline. The safety consequences for the four transmission pipe outcomes are based on the safety consequences associated with individual pipe segments that are also utilized in the LOCTM risk model. The safety consequences associated with the distribution pipe outcomes are based on PHMSA incident data; high and low population density classifications are aligned with the LOCDM risk model.

Similarly, reliability consequences associated with the transmission pipe outcomes are based on reliability consequences associated with transmission pipeline segments. Reliability consequences associated with the distribution pipe outcomes are based on information consistent with the LOCDM risk model.

Financial consequences for all LOC outcomes were based on PHMSA reportable incident data.[5] PG&E relied upon these data to determine financial consequences for all LOC outcomes since the consequences associated with the LOC events that PG&E has experienced are not necessarily representative of consequences that might be realized for these outcomes.

Table 3-5 below shows the consequences of the risk event. Model attributes are discussed in Exhibit (PG&E-2), Chapter 2.

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5 An “Incident” is as defined as an event that involves a release of gas and that results in one or more of the following consequences: death or personal injury necessitating in-patient hospitalization; estimated property damage of $50,000 or more (in 1984 dollars); and/or, unintentional estimated gas loss of three million cubic feet or more. 49 CFR § 191.3.

TABLE 3-5
RISK MODEL CONSEQUENCE SUMMARY

	CoRE	%Freq	%Risk	Freq	Natural Units Per Event			Monetized Levels (2023 $M) of a Consequence Per Event			CoRE (risk-adjusted 2023 $M)			Natural Units per Year			Expected Loss per Year (2023 $M)			Attribute Risk Score (risk-adjusted 2023 $M)		
					Safety	Gas Reliability	Financial	Safety	Gas Reliability	Financial	Safety	Gas Reliability	Financial	Safety	Gas Reliability	Financial	Safety	Gas Reliability	Financial	Safety	Gas Reliability	Financial
					EF/event	#cust/event	$M/event	$M	$M	$M				EF/yr	#cust/yr	$M/yr	$M/yr	$M/yr	$M/yr			
LOC - Transmission - HCA	283.1	1%	73%	0.05	3.26	496	1.7	49.65	0.78	1.71	280.01	1.01	2.08	0.16	24.75	0.09	2.48	0.04	0.09	13.97	0.05	0.10
LOC - Transmission - MCA	106.0	0%	12%	0.02	1.53	557	1.4	23.28	0.87	1.44	103.20	1.17	1.66	0.03	12.30	0.03	0.51	0.02	0.03	2.28	0.03	0.04
LOC - Transmission - (IOC = 0 or leak mode on Non-HCA/MCA)	16.0	2%	10%	0.12	0.30	578	1.4	4.53	0.91	1.45	13.04	1.34	1.66	0.03	67.15	0.17	0.53	0.11	0.17	1.52	0.16	0.19
LOC - Distribution - Low Pop. Dens.	5.9	1.0%	1.9%	0.06	0.19	491	0.6	2.86	0.77	0.63	3.21	1.47	1.19	0.01	30.37	0.04	0.18	0.05	0.04	0.20	0.09	0.07
Benign	0.05	96%	1.5%	5.8	-	-	0.05	-	-	0.05	-	-	0.05	-	-	0.28	-	-	0.28	-	-	0.28
LOC - Distribution - High Pop. Dens.	20.90	0.2%	1.1%	0.01	0.77	526	0.6	11.68	0.83	0.56	18.58	1.57	0.75	0.01	5.54	0.01	0.12	0.01	0.01	0.20	0.02	0.01
LOC - Transmission - (IOC > 0 & rupture mode on Non-HCA/MCA)	11.12	0.1%	0.2%	0.003	0.26	920	1.4	3.91	1.44	1.45	7.33	2.13	1.66	0.00	2.79	0.00	0.01	0.00	0.00	0.02	0.01	0.01
Aggregated	3.19	100%	100%	6.0	0.04	24	0.1	0.64	0.04	0.10	3.02	0.06	0.12	0.25	142.90	0.62	3.83	0.22	0.62	18.18	0.35	0.70

C. 2023-2026 Control and Mitigation Plan

Tables 3-6 and 3-7 list the controls and mitigations PG&E included in its 2020 RAMP and 2023 GRC and is including in this 2024 RAMP (2024-2026 and 2027-2030). The tables provide visibility on the status of controls and mitigations (e.g., whether they are on-going or no longer in place) as well as changes to controls and mitigations.

In the following sections PG&E describes the controls and mitigations in place during the 2023-2026 period. PG&E then discusses new mitigations and/or significant changes to mitigations and/or controls during the 2027-2030 periods.

TABLE 3-6
CONTROLS SUMMARY

Line No.	Control Number and Name[(a)]	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2023-2026)	2024 RAMP (2027-2030)
1	LRGOP-C001 (2020 RAMP) – Corrective Maintenance	X			
2	LRGOP-C002 (2020 RAMP) – Gas Quality Assessment	X			
3	LRGOP-C003 (2020 RAMP) – Preventive Maintenance	X			
4	LRGOP-C004 (2020 RAMP) – Regulator Station Component Replacements and Routine Work	X			
5	LRGOP-C005 (2020 RAMP) – Regulator Station Rebuilds	X			
6	LRGOP-C006 (2020 RAMP) – Other Operations and Maintenance	X			
7	LRGOP-C007 (2020 RAMP) – Foundational Activities Programs	X			
8	LRGOP-C001 – Perform Simple Station Rebuilds		X	X	X
9	LRGOP-C002 – Perform Complex Station Rebuilds		X	X	X
10	LRGOP-C003 – Perform Transmission Terminal Upgrade		X	X	X
11	LRGOP-C004 – Routine Spend M&C		X	X	X
12	LRGOP-C005 – Gas Quality Assessment – Expense		X	X	X
13	LRGOP-C006 – FIMP Risk Assessment		X	X	X
14	LRGOP-C007 – Station Operations		X		
15	LRGOP-C008 – GD Reg Station Rebuild		X	X	X
16	LRGOP-C009 – GD Reg Station Component Replacements		X	X	X
17	LRGOP-C010 – Operate Transmission Pipelines		X		
18	LRGOP-C011 – Vegetation Management		X	X	X
19	LRGOP-C012 – Meter Maintenance		X	X	X
20	LRGOP-C013 – Major Event – Distribution Gas		X	X	X
21	LRGOP-C014 – Gas Distribution Control Center (GDCC) Operations		X		
22	LRGOP-C015 – Gas Transmission and Storage (GT&S) Operations		X		
23	LRGOP-C016 – Transmission SCADA Maintenance		X	X	X
24	LRGOP-C017 – Distribution SCADA Maintenance		X	X	X
25	LRGOP-C018 – Distribution Regulator Maintenance		X	X	X
26	LRGOP-C019 – Farm Tap Maintenance		X	X	X
27	LRGOP-C020 – Transmission Regulator Maintenance		X	X	X

(a) Controls included in the 2020 RAMP are labeled with "(2020 RAMP)" to distinguish between Control Numbers used in the 2020 RAMP Report and Control Numbers used in the 2023 GRC and 2024 RAMP.

TABLE 3-7
MITIGATIONS SUMMARY

Line No.	Mitigation Name and Number[(a)]	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2023-2026)	2024 RAMP (2027-2030)
1	LRGOP-M001 (2020 RAMP) – Critical Documents Program	X	Became M004	Not included. Program completed.	Not included. Program completed.
2	LRGOP-M002 (2020 RAMP) – HPR Replacement	X	Became M005		
3	LRGOP-M003 (2020 RAMP) –SCADA Visibility	X	Split into M001, M006, and M007		
4	LRGOP-M004 (2020 RAMP) – Station OPP Enhancements	X	Split into M002 and M003		
5	LRGOP-M001 – GT SCADA Visibility		X	X	X
6	LRGOP-M002 – GT OPP Program		X	X	X
7	LRGOP-M003 – GD OPP Program		X	X	X
8	LRGOP-M004 – Critical Documents Program		X	Not included. Program completed.	Not included. Program completed.
9	LRGOP-M005 – HPR Program		X	X	X
10	LRGOP-M006 – GD SCADA Visibility (ERX)		X	X	X
11	LRGOP-M007 – GD SCADA Visibility (RTU)		X	X	X

(a) Mitigations included in the 2020 RAMP are labeled with “(2020 RAMP)” to distinguish between Mitigation Numbers used in the 2020 RAMP Report and Mitigation Numbers used in the 2023 GRC and 2024 RAMP.

1. Controls

PG&E identified seven controls for this risk in the 2020 RAMP. In the 2023 GRC, PG&E identified 20 controls. PG&E is proposing the same controls for this risk as it proposed in the 2023 GRC, with the exception of four controls that, upon subsequent review, are considered operational in nature. The four controls which are excluded are:

- LRGOP-C007 – Station Operations (Maintenance Activity Type [MAT] JPN);
- LRGOP-C010 – Operate Transmission Pipelines (MAT JOK);
- LRGOP-C014 – GDCC Operations (MAT FGA)[6]; and
- LRGOP-C015 – GT&S Operations (MAT CMA).

As a result, PG&E is proposing 16 controls for this risk in the 2024 RAMP.

LRGOP-C001 – Perform Simple Station Rebuilds: This program rebuilds transmission simple stations to replace old and/or obsolete equipment and piping, upgrade configurations to meet current design standards and system operating needs and address any issues with station operations and/or maintenance. Rebuilds can involve relocating stations as appropriate.

LRGOP-C002 – Perform Complex Station Rebuilds: This program rebuilds transmission complex stations to replace old and/or obsolete equipment and piping, upgrade configurations to meet current design standards and system operating needs and address any issues with station operations and/or maintenance. Rebuilds can involve relocating stations as appropriate.

LRGOP-C003 – Perform Transmission Terminal Upgrade: This program performs upgrades to PG&E's gas terminals that are required to maintain reliability of the transmission system. Upgrade work includes replacing piping, valves, metering equipment, pipe supports, and SCADA equipment. This program covers selected equipment upgrades at terminals and the rebuild of Brentwood Terminal.

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6 GDCC Operations is considered a foundational program that supports LRGOP-C013; additional information is presented in Section C.3.

LRGOP-C004 – Routine Spend M&C: This control consists of the GT routine M&C capital and expense programs. PG&E continuously evaluates its transmission stations to identify issues related to obsolescence, condition, and performance. As stations age and equipment degrades and/or becomes obsolete, stations may not meet current operational needs. Projects addressed by this control are those that arise during normal operation and must be performed to maintain current levels of service and reliability. Typical projects include repair or replacement of failed or malfunctioning equipment and instrumentation, inspection and testing of asset components, and modifications to address equipment safety or performance.

LRGOP-C005 – Gas Quality Assessment – Expense: This control ensures that the quality of gas delivered into the PG&E system is suitable for transmission and distribution as well as end users; it also ensures that gas quality meets regulatory requirements. The program manages risk associated with solids, liquids, debris, and overall gas quality in the pipeline system. Gas quality scope is expansive and includes, but is not limited to, gas constituents, BTU levels, odorization, and renewable natural gas interconnections. One important aspect of the program is ensuring that natural gas is properly odorized, and the program includes a focus on odor fade. The program also includes measurement support pertaining to the design, selection, and operation of meters across the territory. Processes and procedures are established to ensure the gas transported in PG&E pipelines and delivered to customers is safe and compliant.

LRGOP-C006 – Facilities Integrity Management Program (FIMP) Risk Assessment: This control includes activities associated with continuous data improvement, risk identification and assessment, and investigation of best practices in facility integrity management. Examples include identification of data needs and development of datasets and tools to inform asset management decision-making; root cause analyses of facility-related events to identify threats and risks; development of station-specific risk assessment capabilities; benchmarking studies of work practices, technologies, and operator performance; and pilot studies to assess new technologies and processes prior to implementation.

LRGOP-C008 – GD Reg Station Rebuild: This control consists of complete rebuilds of distribution district regulator stations (Non-HPR-Type). Rebuilds are performed to replace old and obsolete equipment and piping, upgrade configurations to meet current design standards and system operating needs, and to address any issues with station operation and/or maintenance. Rebuilds can involve relocating stations as appropriate.

LRGOP-C009 – GD Reg Station Component Replacements: This control focuses on replacing equipment that is obsolete or is experiencing issues as well as adding specific equipment necessary to ensure reliable station operation. Targeted component replacements are performed when stations do not require full rebuilds.

LRGOP-C011 – Vegetation Management: This control performs routine weed abatement to provide accessibility for the completion of operations and maintenance tasks. This control covers weed abatement in and around multiple types of PG&E facilities, including transmission and meter stations.

LRGOP-C012 – Meter Maintenance: This control involves preventive and corrective maintenance to gas metering and gas quality equipment. Examples of equipment addressed include operational meters, chromatographs, sulfur analyzers, and odorizers. This control includes sampling and testing performed to verify gas quality.

LRGOP-C013 – Major Event - Distribution Gas: This control involves (repair) work performed only in the event of a major event (e.g., wildfire, flood, earthquake).

LRGOP-C016 – Transmission SCADA Maintenance: This control involves preventive and corrective maintenance on transmission SCADA equipment including RTUs, Electronic Pressure Recorders (ERX), transmitters, and transducers. Activities also include investigation of and response to SCADA alarms.

LRGOP-C017 – Distribution SCADA Maintenance: This control involves preventive and corrective maintenance on distribution SCADA equipment including RTUs, ERXs, transmitters, and transducers. Activities also include investigation of and response to SCADA alarms.

LRGOP-C018 – Distribution Regulator Maintenance: This control includes required maintenance work for district regulator stations. Activities include routine inspection and maintenance of equipment including inlet/outlet fire valves and calibration of pressure recorders.

LRGOP-C019 – Farm Tap Maintenance: This control involves maintenance for farm tap regulator sets including atmospheric corrosion inspections and safety-related pressure and lock-up tests to ensure regulating equipment is operating as intended.

LRGOP-C020 – Transmission Regulator Maintenance: This control includes preventative and corrective maintenance at transmission regulator stations. Examples of equipment addressed include regulators, automated valves, manual valves, odorizers, separators, and filters.

2. Mitigations

LRGOP-M001 – GT SCADA Visibility: The GT SCADA Visibility Program installs SCADA at transmission stations and low points of elevation in the transmission system to enable a high degree of monitoring and control for the Gas Transmission Control Center (GTCC). Pressure monitoring upstream of stations enables operators to maintain proper inlet pressures, and downstream pressure monitoring plays a key role in reducing the risk of large OP events since it provides data to operators to help detect OP conditions as well as large leaks and ruptures. SCADA data can be used not only to detect OP conditions but also operational issues that have the potential to escalate into large OP events.

LRGOP-M002 – GT OPP Program: This mitigation consists of the transmission portion of the M&C Station OPP Enhancements Program. The capital portion of the mitigation focuses on modifying or adding station equipment to provide secondary OPP. The practice of installing secondary OPP for OP risk reduction is supported by multiple benchmarking activities and is considered an industry-leading practice. The facilities addressed by this mitigation are pilot-operated facilities, namely the Transmission LVC-Type Facilities. Rebuilds or retrofits are performed to meet current design standards which incorporate secondary OPP. Pilot-operated stations, when compared to other M&C facilities, are subject to a higher likelihood of OP events than other station designs. These station types have a regulator and monitor (primary OPP) that can both fail in the "open" position due to a single cause (e.g., contaminants such as liquids, sulfur, or debris in the system).

LRGOP-M003 – GD OPP Program: This mitigation consists of the distribution portion of the M&C Station OPP Enhancements Program. The capital portion of the mitigation focuses on modifying or adding station equipment to provide secondary OPP. The practice of installing secondary OPP for OP risk reduction is supported by multiple benchmarking activities and is considered an industry-leading practice. The facilities addressed by this mitigation are pilot-operated facilities, namely the Distribution District Regulator Stations. Pilot-operated stations, when compared to other M&C facilities, are subject to a higher likelihood of OP events than other station designs. These station types have a regulator and monitor (primary OPP) that can both fail in the "open" position due to a single cause (e.g., contaminants such as liquids, sulfur, or debris in the system).

LRGOP-M005 – HPR Program: This program consists of removal or rebuild of HPR-Type facilities (including both HPR-Type district regulator stations and farm tap regulator sets) to address aging/obsolete equipment, corrosion issues, and designs not consistent with current design standards. Prior to the creation of this program, many of PG&E's HPR-Type facilities were old and had not been subject to frequent maintenance. As pressure regulating facilities age, equipment degrades and/or becomes obsolete; facilities may not meet current operational needs and safety issues can arise. One of the motivations behind the creation of this program was the accelerated leak survey of the transmission system in 2010[7] where a significant number of leaks were found at HPR-Type facilities. This mitigation program has been on-going, and PG&E's intent is that once all HPRs have been removed or rebuilt through the HPR Program, future HPR replacements or rebuilds will be covered within ongoing M&C asset management programs (e.g., an expansion of LRGOP-C008).

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7 PG&E's Accelerated Natural Gas Transmission System Aerial and Ground Leak Survey Trends Report, (Feb. 1, 2011).

LRGOP-M006 – GD SCADA Visibility (ERX): The ERX component of the GD SCADA Visibility Program installs ERX SCADA devices to monitor distribution regulator stations or hydraulically independent systems (HIS) based on PG&E's established monitoring criteria. These devices are generally installed at stations that utilize spring-operated regulators. The installation of new distribution stations or mainline pipe for capacity and/or reliability enhancements can result in the creation of new HISs, and new ERX devices must be installed on the new HISs that meet criteria for SCADA monitoring. Additional ERX devices are also installed to address blind spots and sensitive locations in the system.

LRGOP-M007 – GD SCADA Visibility (RTU): The RTU component of the GD SCADA Visibility Program installs RTU devices at distribution regulator stations. These devices are generally installed at stations that utilize pilot-operated regulators. RTU devices are capable of real-time data transmission which allows for trending of data to detect potential OP conditions.

TABLE 3-8
PLANNED MITIGATIONS 2024-2026

Line No.	Mitigation ID	Mitigation Name	Unit of Measurement[(a)]	Planned Units of Work 2024	2025	2026	Total
1	LRGOP-M001	GT SCADA Visibility	Installations	8	4.5	4.5	17
2	LRGOP-M002	GT OPP Program	Stations	30	32	34	96
3	LRGOP-M003	GD OPP Program	Stations	50	50	50	150
4	LRGOP-M005	HPR Program	HPRs	80	80	80	240
5	LRGOP-M006	GD SCADA Visibility (ERX)	Installations	9	10	10	29
6	LRGOP-M007	GD SCADA Visibility (RTU)	Installations	39	39	39	117

(a) The units of work are presented as used in the RAMP model because the model requires that units of work are standardized. These may differ in some instances from "rate case" units – the units referred to in PG&E's GRC or other proceedings.

For additional details see Exhibit (PG&E-3), WP GO-LRGOP-F.

TABLE 3-9
MITIGATION COST ESTIMATES
2024-2026 EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Mitigation ID	Mitigation Name	2024	2025	2026	Total
1	LRGOP-M002	GT OPP Program	$966	$947	$928	$2,840
2	LRGOP-M003	GD OPP Program	1,197	1,173	1,150	3,520
3		Total	$2,163	$2,120	$2,077	$6,360

For additional details see Exhibit (PG&E-3), WP GO-LRGOP-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

TABLE 3-10
MITIGATION COST ESTIMATES
2024-2026 CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Mitigation ID	Mitigation Name	2024	2025	2026	Total
1	LRGOP-M001	GT SCADA Visibility	$3,000	$1,568	$1,537	$6,105
2	LRGOP-M002	GT OPP Program	19,810	19,810	19,810	59,430
3	LRGOP-M003	GD OPP Program	7,497	7,497	7,497	22,491
4	LRGOP-M005	HPR Program	16,968	16,968	16,968	50,903
5	LRGOP-M006	GD SCADA Visibility (ERX)	446	533	496	1,475
6	LRGOP-M007	GD SCADA Visibility (RTU)	11,110	11,110	11,110	33,330
7		Total	$58,831	$57,485	$57,417	$173,734

For additional details see Exhibit (PG&E-3), WP GO-LRGOP-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

3. Foundational Activities

As discussed in Exhibit (PG&E-2), Chapter 2, foundational activities are programs that enable two or more control or mitigation programs but do not directly reduce the consequences or the likelihood of risk events. Table 3-11 describes foundational activities that meet this definition and includes: (1) information on the control or mitigation programs enabled and (2) the foundational activity program costs on a Net Present Value (NPV) basis that are included in Cost Benefit Ratio (CBR) calculations for enabled control or mitigation programs.

TABLE 3-11
2027-2030 FOUNDATIONAL ACTIVITIES
(MILLIONS OF DOLLARS)

Line No.	Foundational Activity ID [(a)]	Foundational Activity Name	Foundational Activity Description	Enabled Control and Mitigation IDs [(a)]	Net Present Value (NPV)[(b)]
1	LOCTM-C038	Stan-Pac Expense	See description in in Exhibit (PG&E 3), Chapter 1.	LOCTM-C016, LRGOP-C011	$5.82
2	LOCDM-C013	Training, Gas Qualifications	See description in in Exhibit (PG&E 3), Chapter 2.	LOCDM-C008, LRGOP-C013	2.92
3	LOCDM-C015	Gas Distribution Control Center Operations	See description in in Exhibit (PG&E 3), Chapter 2.	LOCDM-C008, LRGOP-C013	23.57
4		Total			$32.31

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

(b) NPV uses a base year of 2023.

For additional details see Exhibit (PG&E-3), WP GO-LRGOP-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

D. 2027-2030 Proposed Control and Mitigation Plan

1. Changes to Controls

As described in Sections C.1, there are 16 controls for this risk; no changes are proposed for the 2027-2030 time period. Table 3-12 below shows the cost estimates, risk reduction values, and CBRs for these programs as planned for the 2027-2030 time period.

TABLE 3-12
CONTROLS COST ESTIMATES, RISK REDUCTION AND CBR
2027-2030

Line No.	Control ID [(a)]	Control Name	2027	2028	2029	2030	Thousands of Nominal Dollars: Program Cost [A]	Thousands of Nominal Dollars: Foundational Activity Cost [B]	Millions of Dollars (NPV)[(b)]: Risk Reduction [C]	Millions of Dollars (NPV)[(b)]: CBR[(c)] [C]/([A]+[B])
1	LRGOP-C001	Perform Simple Station Rebuilds	$7,680	$7,897	$8,129	$8,357	$30.3	–	$0.5	<0.1
2	LRGOP-C002	Perform Complex Station Rebuilds	19,882	20,446	21,047	21,637	78	–	0.6	<0.1
3	LRGOP-C003	Perform Transmission Terminal Upgrade	11,884	12,215	12,567	12,919	47	–	1.2	<0.1
4	LRGOP-C004	Routine Spend M&C	10,689	10,848	11,022	11,197	38	–	66.2	1.7
5	LRGOP-C005	Gas Quality Assessment - Expense	1,412	1,384	1,356	1,329	4	–	122.4	32.2
6	LRGOP-C006	FIMP Risk Assessment	1,731	1,696	1,662	1,629	5	–	9.8	2.1
7	LRGOP-C008	GD Reg Station Rebuild	50,510	51,319	52,264	53,348	200	–	0.3	<0.1
8	LRGOP-C009	GD Reg Station Component Replacements	12,946	13,154	13,395	13,673	51	–	1.6	<0.1
9	LRGOP-C011, LOCTM-C016	Vegetation Management	1,640	1,608	1,575	1,544	4	0.0	12.5	2.8
10	LRGOP-C012	Meter Maintenance	2,383	2,335	2,288	2,242	6	–	9.4	1.5
11	LRGOP-C013, LOCDM-C008	Major Event – Distribution Gas	460	451	442	433	1	0.0	7.8	6.2
12	LRGOP-C016	Transmission SCADA Maintenance	595	583	571	560	2	–	0.9	0.5
13	LRGOP-C017	Distribution SCADA Maintenance	1,882	1,844	1,807	1,771	5	–	0.2	<0.1
14	LRGOP-C018	Distribution Regulator Maintenance	8,542	8,371	8,204	8,040	23	–	0.3	<0.1
15	LRGOP-C019	Farm Tap Maintenance	678	664	651	638	2	–	0.1	<0.1
16	LRGOP-C020	Transmission Regulator Maintenance	5,387	5,280	5,174	5,071	14	–	10.9	0.8
17		Total	$138,299	$140,094	$142,155	$144,387				

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

(b) NPV uses a base year of 2023.

(c) CBR calculations include allocated Foundational Activity Program costs.

For additional details see Exhibit (PG&E-3), WP GO-LRGOP-F.
The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

2. Changes to Mitigations

PG&E is not proposing any new mitigations in 2027-2030. The volume of work PG&E plans to complete in 2027-2030 is shown in Table 3-13 below. Tables 3-14 and 3-15 below show the cost estimates, CBRs, and risk reduction scores for these expense and capital programs, respectively, as planned for the 2027-2030 time period.

TABLE 3-13
PLANNED MITIGATIONS 2027-2030

Line No.	Mitigation ID	Mitigation Name	Unit of Measurement[(a)]	Planned Units of Work 2027	2028	2029	2030	Total
1	LRGOP-M001	GT SCADA Visibility	Installations	5	5	5	5	20
2	LRGOP-M002	GT OPP Program	Stations	36	38	40	42	156
3	LRGOP-M003	GD OPP Program	Stations	51	52	53	54	210
4	LRGOP-M005	HPR Program	HPRs	80	80	80	80	320
5	LRGOP-M006	GD SCADA Visibility (ERX)	Installations	10	10	10	10	40
6	LRGOP-M007	GD SCADA Visibility (RTU)	Installations	40	40	41	42	163

(a) The units of work are presented as used in the RAMP model because the model requires that units of work are standardized. These may differ in some instances from "rate case" units – the units referred to in PG&E's GRC or other proceedings.

For additional details see Exhibit (PG&E-3), WP GO-LRGOP-F.

TABLE 3-14
MITIGATION COST ESTIMATES, RISK REDUCTION, CBR AND FACTORS AFFECTING SELECTION
2027-2030 EXPENSE

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[a]				
							[A]	[B]	[C]	[C]/([A]+[B])	
Line No.	Mitigation ID	Mitigation Name	2027	2028	2029	2030	Program Cost	Foundational Activity Cost	Risk Reduction	CBR[b]	Factors Affecting Selection
1	LRGOP-M002	GT OPP Program	$909	$891	$873	$856	$81.8	$0.0	$79.5	1.0	Risk Tolerance[c]
2	LRGOP-M003	GD OPP Program	1,127	1,104	1,082	1,060	33.1	0.0	0.5	<0.1	Risk Tolerance[c]
3		Total	$2,036	$1,995	$1,955	$1,916					

For additional details see Exhibit (PG&E-3), WP GO-LRGOP-F.

(a) NPV uses a base year of 2023.

(b) CBR calculations include allocated Foundational Activity program costs.

(c) See Table 3-15. The capital and expense portions of the OPP mitigation programs are grouped for transmission and distribution, respectively. Program Cost, Risk Reduction and CBR values for the combined capital and expense programs are shown in Table 3-14.

For additional details see Exhibit (PG&E-3), WP GO-LRGOP-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

TABLE 3-15
MITIGATION COST ESIMATES, RISK REDUCTION, CBR AND FACTORS AFFECTING SELECTION
2027-2030 CAPITAL

Line No.	Mitigation ID	Mitigation Name	Thousands of Nominal Dollars				Millions of Dollars (NPV)[a]			[C]/([A]+[B])	Factors Affecting Selection
			2027	2028	2029	2030	[A] Program Cost	[B] Foundational Activity Cost	[C] Risk Reduction	CBR[b]	
1	LRGOP-M001	GT SCADA Visibility	$1,571	$1,616	$1,664	$1,710	$6.2	$0.0	$0.6	0.1	Modeling Limitations
2	LRGOP-M002	GT OPP Program	20,164	20,726	21,324	21,921	81.8	0.0	79.5	1.0	Risk Tolerance
3	LRGOP-M003	GD OPP Program	7,593	7,711	7,849	8,011	33.1	0.0	0.5	<0.1	Risk Tolerance
4	LRGOP-M005	HPR Program	17,186	17,453	17,764	18,132	68.2	0.0	0.2	<0.1	Operational and Execution Considerations
5	LRGOP-M006	GD SCADA Visibility (ERX)	503	510	519	530	2.0	0.0	0.0	<0.1	Modeling Limitations
6	LRGOP-M007	GD SCADA Visibility (RTU)	11,253	11,428	11,631	11,872	44.6	0.0	0.4	<0.1	Modeling Limitations
7		Total	$58,270	$59,445	$60,750	$62,178					

(a) NPV uses a base year of 2023.

(b) CBR calculations include allocated Foundational Activity Program costs.

For additional details see WP GO-LRGOP-F.

The cost estimates in this table are generally based on PG&E’s 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

3. Factors Affecting Mitigation Selection

Tables 3-13, 3-14, 3-15 summarize PG&E's proposed mitigations during the 2027-2030 period including the rationale for selecting the proposed mitigations. As shown in Table 3-15, the programs with the highest risk reduction and CBR values are the GT OPP Program (CBR = 0.971) and GT SCADA Visibility (CBR = 0.092). Additional information on the rationale for selecting mitigations is provided below.

Risk Tolerance: The Commission has recognized the need for discussion and clear guidance on Risk Tolerance and has expressed its intention to address this topic in future Phases of the Risk OIR. In the meantime, PG&E's risk mitigation strategies are selected to ensure that safety remains PG&E's top priority even when the quantitative RAMP modelling indicates the costs are higher than the modeled value of risk reduction. Although large OP events are rare when modern regulation equipment is operating within ideal operating tolerance, when large OP events occur, the consequences can be devastating. Since large OP events have the potential to result in significant safety consequences, all of the mitigations presented in this chapter can be considered to address risk tolerance. With respect to the GT and GD OPP Programs additional discussion follows:

- **LRGOP-M002 – GT OPP Program:** The GT OPP Program has a CBR value of 0.971, which indicates that the large OP risk reduction benefits provided by the program are nearly equivalent to the cost. This program addresses the Transmission – LVC-Type Facilities that that are subject to the highest observed rate of large OP events; these facilities also have a relatively high proportion of large OP events that progress to LOC downstream.
- **LRGOP-M003 – GD OPP Program:** While the GD OPP Program has a relatively low CBR, this may be due to a potential underestimation of consequences on downstream distribution pipeline. This program addresses facilities that have a known common failure mode, whereby the regulation equipment and primary OPP have the potential to both "fail open" due to the same cause. The installation of secondary OPP performed by this program mitigates this common failure mode.

No funding was adopted for either of these programs in the 2023 GRC Decision. However, PG&E is proposing units for these programs through 2030 at a significantly reduced pace. PG&E plans to take a strategic approach to these programs going forward by identifying risk remaining in the system and specific high-risk locations that remain to be mitigated. This assessment of specific station locations is currently in progress and is anticipated to inform program forecasts presented in the 2027 GRC.

Modeling Limitations: The risk reduction and CBR values presented in this chapter provide an assessment of the benefits provided by the programs towards reducing large OP risk alone. This chapter does not present assessments of other benefits provided by several of the mitigation programs. More specifically, there are benefits that extend beyond large OP risk reduction for the three SCADA mitigation programs presented in this chapter, namely:

- LRGOP-M001 – GT SCADA Visibility;
- LRGOP-M006 – GD SCADA Visibility (ERX); and
- LRGOP-M007 – GD SCADA Visibility (RTU).

PG&E installs SCADA devices in key locations within the gas system including regulator stations due to their importance in operating a safe and reliable gas system. SCADA devices allow Gas Control Center personnel to monitor and operate the gas system and to mitigate potentially abnormal conditions. SCADA visibility enables PG&E to have insight into real-time operations and execute appropriate response protocols.

Operational and Execution Considerations: PG&E executes a three-pronged asset management strategy[8] for its regulator stations and regulator sets, namely maintenance, targeted equipment replacement, and station and regulator set rebuilds. Equipment at regulator stations and regulator sets is known to degrade with time, and this strategy is intended to address degradation in asset condition and performance and ensure that the regulator stations and regulator sets can perform their intended function so PG&E can reliably serve its customers. Proactive asset replacement including steady-state asset rebuild programs is a prudent approach to

[8] A.21-06-021, PG&E's 2023 GRC, Exhibit (PG&E-3), WP 6-88.

managing risk associated with regulation facilities. If a certain steady-state level of asset replacement is not maintained, there will come a time when the rate of failure of these assets will exceed PG&E's ability to address them, either from the standpoint of a skilled and qualified workforce executing the work or from the perspective of the resulting cost burden to rate payers. There are a few key operational and execution considerations to consider with respect to the HPR Program (LRGOP-M005) in particular.

First, it is important to understand that the HPR Program was not developed to mitigate large OP risk. In February 2011, PG&E reported that most of the leaks on the transmission system were on the HPR facilities.[9] Subsequently, PG&E began this program to rebuild or replace HPR-Type facilities in order to address equipment deterioration, obsolescence, and legacy designs. Second, from an asset management perspective, it is critical that PG&E maintain some rate of steady-state asset replacement for its regulator stations and regulator sets. This program represents the third prong of PG&E's asset management strategy for HPR-Type facilities. There is no other program that performs steady-state asset replacement for HPR-Type facilities other than the HPR Program.

This program has been considered a mitigation in PG&E's RAMP filings because the pace of the program exceeded that required to maintain a steady-state asset replacement age between 60-80 years.[10] PG&E communicated in the 2023 GRC that the program would eventually transition to an ongoing control program similar to its other station rebuild and component replacement programs.

Even though the forecast for the HPR Program was not adopted in the 2023 GRC Decision, PG&E is proposing units for this program through 2030 because there are remaining HPR-Type units to be addressed and some level of steady-state asset replacement may continue to be required.

Compliance Requirements: There is the potential for compliance requirements to influence PG&E's large OP risk mitigation programs in the future. More specifically, proposed revisions to pipeline safety regulations

9 PG&E's Accelerated Natural Gas Transmission System Aerial and Ground Leak Survey Trends Report, (Feb. 1, 2011).

10 A.21-06-021, PG&E's 2023 GRC, Exhibit (PG&E-3), WP 6-88.

as presented in the recent PHMSA Notice of Proposed Rulemaking (NPRM) (Docket # PHMSA-2021-0046) have the potential to result in compliance requirements that would likely be addressed by LRGOP-M003 – GD OPP Program. PG&E may propose additional work within this program in the 2027 GRC filing.

E. Alternative Mitigations Analysis

In addition to the proposed mitigations described in Section D above, PG&E considered alternative mitigations as well. The mitigations described in Section D constitute the Proposed Plan. Two Alternative Plans are presented below. Each Alternative Plan consists of several of the proposed mitigations combined with an alternative mitigation. PG&E describes each of the alternative mitigations below; cost estimates, risk reduction, and CBRs are also presented in Tables 3-16, 3-17, 3-18, and 3-19 below.

1. Alternative Plan 1: LRGOP-A001 – Rebuild Single-Run Stations

The distribution portion of the M&C Station OPP Enhancements Program is LRGOP-M003 – GD OPP Program. The capital portion of the mitigation focuses on modifying or adding station equipment to provide secondary OPP on Distribution District Regulator Stations (Non-HPR-Type), which are pilot-operated facilities. The type of secondary OPP that is installed is generally a “slam-shut” device.

Pilot-operated stations are subject to a higher likelihood of OP events than other station types since their design includes a regulator and monitor (primary OPP) that can both fail in the “open” position due to a single cause (e.g., contaminants such as liquids, sulfur, or debris in the system).

Distribution District Regulator Stations (Non-HPR-Type) can be classified by the number of runs they contain. Approximately 500 of these stations are single-run stations. PG&E is currently planning on installing slam-shut devices to mitigate the common failure mode of the station’s regulator and monitor devices at approximately 100 of these stations. However, installing slam-shut devices on single-run stations has the potential to result in negative impacts to downstream customers. To reduce the potential for these negative impacts, PG&E is proposing an alternative that consists of rebuilding these 100 stations to PG&E’s current design standard for pilot-operated regulator stations, which specifies that all new stations must be built with a dual-run configuration as well as slam-shut devices.

Alternative Plan 1 consists of replacing LRGOP-M003 – GD OPP Program with alternative mitigation LRGOP-A001 – Rebuild Single-Run Stations. This alternative mitigation consists of station rebuilds on single-run stations beginning in 2027 and slam-shut retrofits on dual-run stations. The rebuilds would occur at a pace of 25 per year so that the program would address 100 single-run stations by the end of 2030. The remaining units in the program consist of retrofitting stations that are already in a dual-run configuration with secondary OPP (i.e., slam-shut devices). Rebuilds for Distribution District Regulator Stations (Non-HPR-Type) are already an established control program. The station rebuilds that are proposed as part of this alternative mitigation are incremental to station rebuilds that are included within LRGOP-C008 – GD Reg Station Rebuilds.

Although station rebuilds address concerns in addition to OP risk mitigation, PG&E did not choose this alternative because the cost of station rebuilds is significantly higher than the cost of retrofitting stations with slam-shut devices.

TABLE 3-16
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030 EXPENSE

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[a]		
Line No.	Mitigation ID	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	LRGOP-A001	Rebuild Single-Run Stations	$1,127	$1,104	$1,082	$1,060	[b]	[b]	[b]
2		Total	$1,127	$1,104	$1,082	$1,060			

(a) NPV uses a base year of 2023.

(b) See Table 3-16. The expense portion of LRGOP-A001 is required to execute the capital portion. Program Cost, Risk reduction and CBR values for the combined capital and expense program are shown in Table 3-16.

For additional details see Exhibit (PG&E-3), WP GO-LRGOP-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

TABLE 3-17
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030 CAPITAL

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[a]		
Line No.	Mitigation ID	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	LRGOP-A001	Rebuild Single-Run Stations	$55,633	$55,783	$55,933	$56,083	$219.2	0.6	<0.1
2		Total	$55,633	$55,783	$55,933	$56,083			

(a) NPV uses a base year of 2023.

For additional details see Exhibit (PG&E-3), WP GO-LRGOP-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

2. Alternative Plan 2: LRGOP-A002 – Relief Valves Downstream of Single-Run Stations

Alternative Plan 2 is similar to Alternative Plan 1 in that it includes an alternative to installing slam-shut devices at 100 single-run stations. However, instead of rebuilding 100 single-run stations, the alternative mitigation includes installing secondary OPP in the form of a relief valve downstream of the station. Relief valves are widely used in industry and, in contrast to slam-shut devices, they allow gas to continue to flow downstream.

Alternative Plan 2 consists of replacing LRGOP-M003 – GD OPP Program with alternative mitigation LRGOP-A002 – Relief Valves. This alternative mitigation consists of the installation of relief valves downstream of single-run stations beginning in 2027 combined with slam-shut retrofits on dual-run stations. The relief valve installations would occur at a pace of 25 per year so the program would address 100 single-run stations by the end of 2030. The remaining units in the program consist of retrofitting stations that are already in a dual-run configuration with secondary OPP (i.e., slam-shut devices).

PG&E did not choose this alternative because the cost of installing relief valves is still higher than the cost of retrofitting stations with slam-shut devices. Furthermore, since relief valves release natural gas, they have the potential to create safety and environmental impacts that slam-shut devices do not.

TABLE 3-18
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030 EXPENSE

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[a]		
Line No.	Mitigation ID	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	LRGOP-A002	Relief Valves	$1,127	$1,104	$1,082	$1,060	[b]	[b]	[b]
2		Total	$1,127	$1,104	$1,082	$1,060			

(a) NPV uses a base year of 2023.

(b) See Table 3-18. The expense portion of LRGOP-A001 is required to execute the capital portion. Program Cost, Risk reduction and CBR values for the combined capital and expense program are shown in Table 3-18.

For additional details see Exhibit (PG&E-3), WP GO-LRGOP-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

TABLE 3-19
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030 CAPITAL

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[a]		
Line No.	Mitigation ID	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	LRGOP-A002	Relief Valves	$10,148	$10,298	$10,448	$10,598	$43.1	0.5	0.1
2		Total	$10,148	$10,298	$10,448	$10,598			

(a) NPV uses a base year of 2023.

For additional details see Exhibit (PG&E-3), WP GO-LRGOP-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

Application: 24-05-
(U 39 G)
Exhibit No.: (PG&E-4)
Date: May 15, 2024
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT

EXHIBIT (PG&E-4)

ELECTRIC OPERATIONS

PACIFIC GAS AND ELECTRIC COMPANY
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RISK ASSESSMENT AND MITIGATION STRATEGY: WILDFIRE WITH PSPS AND EPSS

A. Executive Summary

Pacific Gas and Electric Company's (PG&E or the Company) stand is that catastrophic wildfires shall stop. Since the last Risk Assessment and Mitigation Phase (RAMP) filing, California has continued to experience catastrophic wildfires due to climate change. Many of these fires have occurred in PG&E's service territory in Northern California, approximately 53 percent of which lies in High Fire Threat District (HFTD) areas as identified by the California Public Utilities Commission (CPUC or Commission).[1] PG&E is committed to reducing the Wildfire Risk and to limiting the disruption from wildfire mitigation efforts for the benefit of our customers and communities throughout California.

The HFTD represents areas where there is an elevated hazard for utility-associated wildfires to occur and spread rapidly. Similarly, communities in the HFTD face an elevated risk from utility-associated wildfires. Given that the Wildfire Risk is predominantly concentrated in HFTD, PG&E has focused its mitigation efforts by reassessing the HFTD every year, creating a High Fire Risk Area (HFRA)[2] zone, which includes HFTD and select areas that HFTD does not cover. For the purposes of our mitigation programs, we cover HFTD and HFRA and collectively refer to these areas as HFTD/HFRA.

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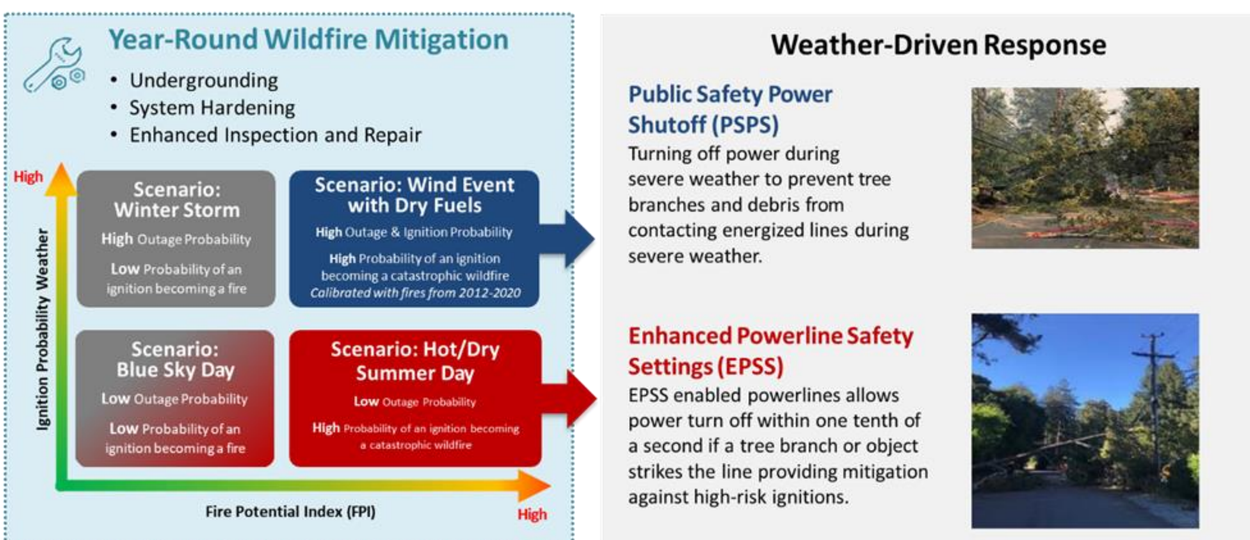
1 The HFTD Map, adopted by the Commission in January 2018, designates three types of fire threat area: Tier 3 ("extreme risk"), Tier 2 ("elevated risk"), and a much smaller Zone 1 (made up of areas on the California Department of Forestry and Fire Protection (CAL FIRE)/U.S. Forest Service High Hazard Zones map that are not subsumed within the Tier 2 and Tier 3 HFTD areas). See D.17-12-024, p. 158, Ordering Paragraph 12, and Appendix D.

2 PG&E developed the HFRA map starting with the HFTD Tier 2 and Tier 3 areas and adjusted it to include locations where an ignition during an offshore wind event could lead to a catastrophic wildfire. The processes PG&E used to develop the HFRA were described in PG&E's 2021 and 2022 WMPs. PG&E will be filing a Petition for Modification with the CPUC asking that some of the areas in the HFRA be added to the HFTD map.

The Baseline Wildfire Risk is defined as a wildfire that may endanger the public, private property, sensitive lands or environment originating from PG&E assets or activities. In the near term, due the use of PSPS and EPSS, we have also defined Wildfire Risk with PSPS and EPSS, to account for the benefits and consequences of operational mitigations such as PSPS and EPSS. Wildfire is the highest-ranked safety risk both with and without PSPS and EPSS.

Over the last several years, PG&E has developed an integrated strategy to manage and reduce ignition risk while we implement permanent risk reduction strategies, such as undergrounding and other system hardening work. At the same time, PG&E is not leaving Wildfire Risk unaddressed in high-risk areas in the short-term. Two key mitigation programs—PSPS and EPSS—are deployed to quickly address the wildfire threat when there's an indication of wildfire exposure. The reason why these two programs are utilized is because they provide weather-driven response to forecasted fire danger. This is best illustrated in Figure 1-1 below. This response reinforces the need for long-term grid resilience.

FIGURE 1-1
WEATHER-DRIVEN RESPONSE TO FORECASTED FIRE DANGER



The PSPS Program temporarily turns off power in specific areas during extreme weather conditions to prevent the electric system from becoming a potential source of ignition. A PSPS is a last-resort measure for keeping customers and communities safe. Similarly, EPSS is a protective technology that allows line protection devices, such as line reclosers, to respond to faults of varying magnitude and rapidly de-energize the line. These faults may occur due to vegetation striking a line, animal contact, third-party contact (e.g., a vehicle hitting a line), or equipment failure. These two programs are mitigations to Wildfire Risk, but they are also incorporated into a broader definition of the risk quantification in this RAMP submission based on CPUC and Office of Energy Infrastructure Safety (OEIS) guidance on representing Wildfire plus the negative impacts driven by the use of PSPS and EPSS.

The Wildfire Risk with PSPS and EPSS is elevated during Red Flag Warning (RFW) conditions and hot, dry summer days. Because of unique conditions of this risk, the PG&E Meteorology team has developed a high-resolution, combined weather and fire danger model that produces a Fire Potential Index (FPI) rating used to help inform and to drive action whenever the fire risk is elevated in PG&E's service territory. The FPI Model combines fire weather parameters (wind speed, temperature, and vapor pressure deficit), dead and live fuel moisture data, topography, and fuel model data to predict the probability of large and/or catastrophic fires. The index, ranging from R1 to R5+, provides forward-looking insight to guide utility operational mitigations like PSPS and EPSS. model that produces a Fire Potential Index (FPI) rating used to help inform and to drive action whenever the fire risk is elevated in PG&E's service territory. The FPI Model combines fire weather parameters (wind speed, temperature, and vapor pressure deficit), dead and live fuel moisture data, topography, and fuel model data to predict the probability of large and/or catastrophic fires. The index, ranging from R1 to R5+, provides forward-looking insight to guide utility operational mitigations like PSPS and EPSS.

In line with the Wildfire Mitigation Plans (WMP) that PG&E has filed with OEIS, PG&E is proposing a broad suite of controls and mitigations to address the key Wildfire Risk drivers. Some of these programs, however, have resulted in reliability degradation to customers, which has been incorporated into a wider definition of Wildfire Risk.

PG&E's proposed mitigations include four broad strategies for understanding and responding to Wildfire Risk:

1) <u>Data Gathering and Continuous Monitoring</u>: PG&E has deployed a suite of Comprehensive Monitoring and Data Collection programs, such as weather

stations, wildfire cameras, and asset inspections, designed to provide insight into changing environmental hazards around our assets. These programs provide continuous monitoring capability that we use to decide what mitigations to deploy, as well as where and when to deploy them.

2) Operational Mitigations: Our integrated strategy includes temporary mitigation programs like PSPS, EPSS and Downed Conductor Detection (DCD). These programs provide on-going risk reduction and influence how we manage the environment around the electric grid. PSPS and EPSS are the most Wildfire Risk reducing and cost-effective programs PG&E deploys. Furthermore, EPSS also includes DCD, which adds efficiency by mitigating potential ignitions that EPSS alone does not detect. PSPS and EPSS are temporary mitigations, meaning if they no longer are deployed operationally, the inherent risk remains on our system. It also should be noted that PG&E's foundational inspection programs for distribution, transmission, and substations have identified assets near/imminent in failure for our emergency maintenance and repair control programs. Operational mitigations also include initiatives we undertake to support customers before, during, and after wildfire events.

3) System Resilience mitigations: For permanent risk reduction activities, the most risk reducing programs PG&E deploys are our long-term System Hardening program (including measures such as undergrounding, overhead (OH) system hardening with covered conductor, line removal, and remote grid) and the transmission line removal work that reduces ignition risk by changing how our grid is constructed. The undergrounding of distribution lines is a multi-year cornerstone program to permanently reduce the Wildfire Risk, reduce PSPS and EPSS outages, and protect the grid from extreme weather events.

4) Customer Awareness and Engagement: In addition to our mitigation initiatives, PG&E proactively engages with our customers and communities to address issues related to wildfire preparation, ongoing safety work, and other public safety and preparedness issues.

PG&E continually evaluates its wildfire mitigation approach to adapt to evolving wildfire threats and incorporates lessons learned from its ongoing efforts, as well as information from customers, communities, academia, and government entities about how to improve the programs' effectiveness and impact. These programs, and PG&E's risk modeling efforts, are dynamic. In response to new information, PG&E may adjust the scope of the programs presented here and/or introduce new programs as part of its forecast in the 2027 General Rate Case (GRC).

Excluding operational mitigations, the Baseline Wildfire Risk today is $21.95 billion. It is also the highest-ranked total risk of PG&E's 32 Corporate Risk Register risks. With operational mitigations, this risk has a 2027 Test Year (TY) Wildfire + PSPS + EPSS Safety Risk Value of $222 million[3] and has a 2027 TY Wildfire + PSPS + EPSS Total Risk Value of $7.666 billion. The main drivers for this risk event are vegetation and equipment failures.

Our 2023 Baseline Wildfire Risk is $21.95 billion, excluding operational mitigations. PG&E forecasts that the Baseline Wildfire Risk would increase year over year due to the changing climate driving extreme weather events if mitigation activity is not undertaken. PG&E is projecting an approximately 10 percent risk increase due to climate change by 2027; this would be offset by an approximately 21 percent decrease attributable to PG&E's permanent mitigations between 2023-2026, largely driven by our System Hardening programs, resulting in a net 11 percent risk reduction by 2027. This results in 2027 TY Baseline Wildfire Risk of $19.63 billion. Compared to the 2027 TY Baseline, PG&E is projecting an approximately 7 percent risk increase due to climate change by 2030, offset by an approximately 22 percent decrease attributable to PG&E's permanent mitigations between 2027-2030, resulting in a net 15 percent risk reduction by 2030. Our 2027-2030 mitigations are primarily driven by the System Hardening programs. These permanent risk reductions exclude risk benefits of our temporary operational mitigations, PSPS and EPSS.

For additional detail on TY Baseline Total and Safety Risk Values, see Figures 1-2 and 1-3, respectively below.

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[3] Includes 2027 TY Baseline Wildfire Safety Risk of $160.2 million, PSPS Safety Risk of $43.8 million, and EPSS Safety Risk of $18.5 million.

FIGURE 1-2
2027 TY BASELINE (WITH AND WITHOUT OPERATIONAL MITIGATION)

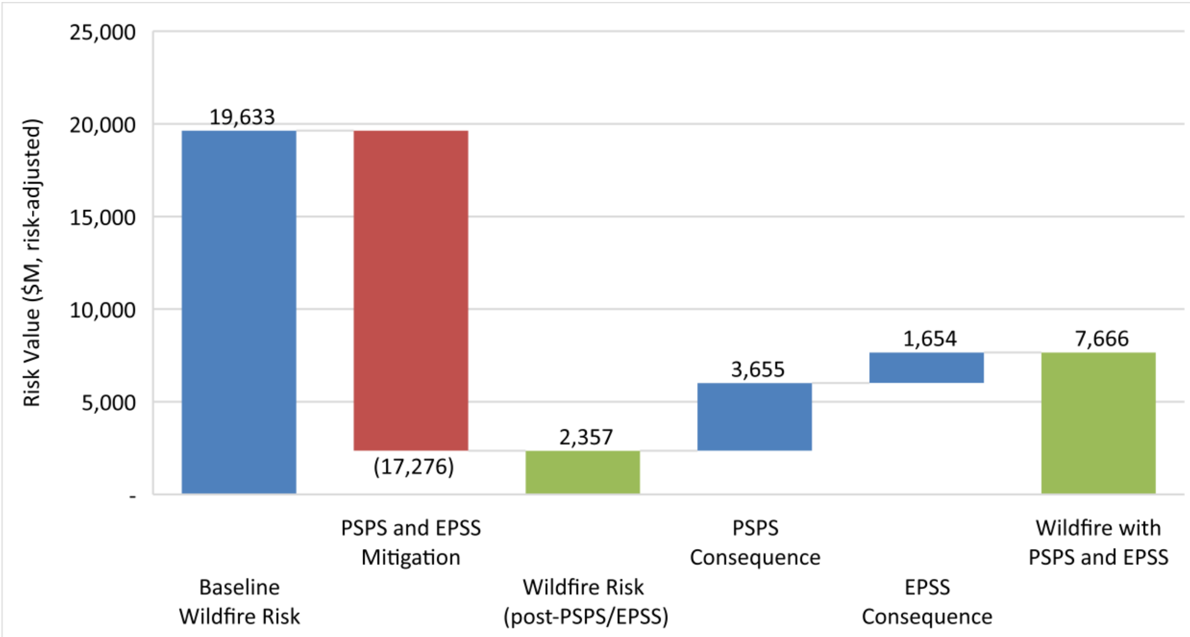
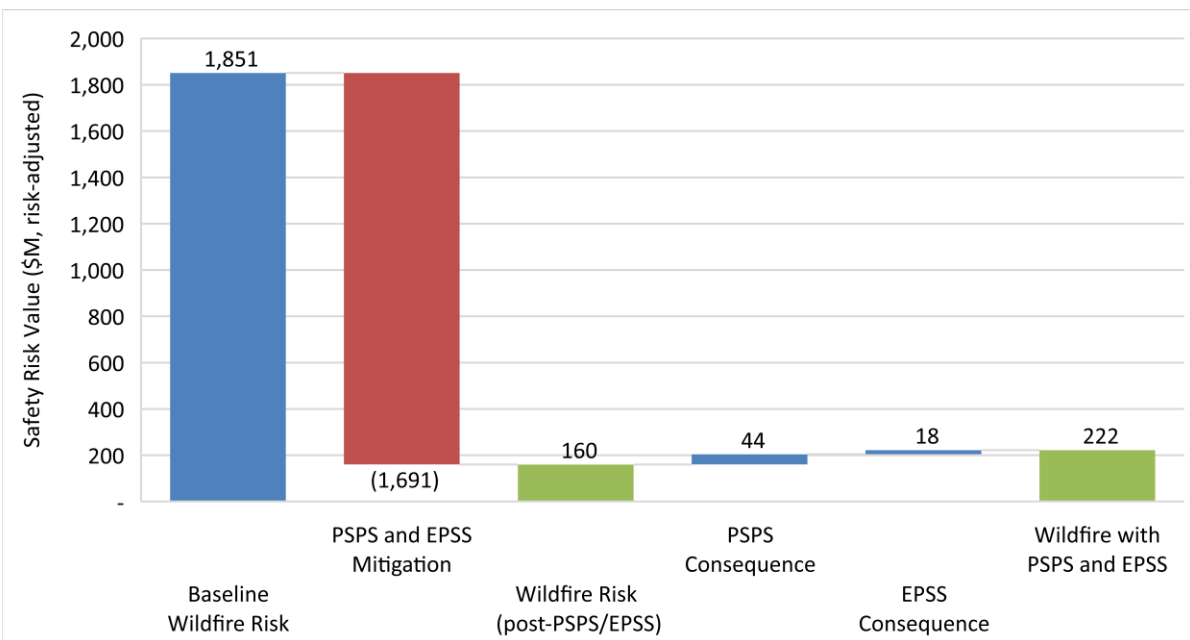


FIGURE 1-3
2027 TY BASELINE SAFETY VALUES (WITH AND WITHOUT OPERATIONAL MITIGATION)



1. Risk Overview

TABLE 1-1
RISK DEFINITION, SCOPE, AND DATA SOURCES

Line No.	Risk Name	Wildfire Risk with PSPS and EPSS
1	Definition	The Baseline Wildfire Risk is defined as a wildfire that may endanger the public, private property, sensitive lands or environment originating from PG&E assets or activities. In the near term due to the use of PSPS and EPSS we have also defined Post PSPS/EPSS Wildfire Risk as Wildfire Risk with PSPS and EPSS. This does account for the benefits and consequences of operational mitigations such as PSPS and EPSS.
2	In Scope	2015 to 2022 PG&E recorded ignition record (CPUC reportable and non-reportable). Other PG&E failure events (e.g., equipment failure without ignition, outage, etc.)
3	Out of Scope	Fire ignitions and associated impacts not related to PG&E electric system assets.
4	Data Quantification Sources[(a)]	PG&E sourced ignitions, CAL FIRE, National Weather Service (NWS), other PG&E data (Outage data, Geographic Information System data, PG&E System Earthquake Risk Assessment (SERA) model, Integrated Logging Information Systems, Transmission Operation Tracking and Logging), Fire Weather Index, WDRM_V3 model outputs, EPSS Outage dataset, Technosylva population impacted, PSPS damages and hazards assessment.

(a) Source documents are provided with the workpapers (WP).

B. Risk Assessment

1. Background and Evolution

a. Wildfire Risk

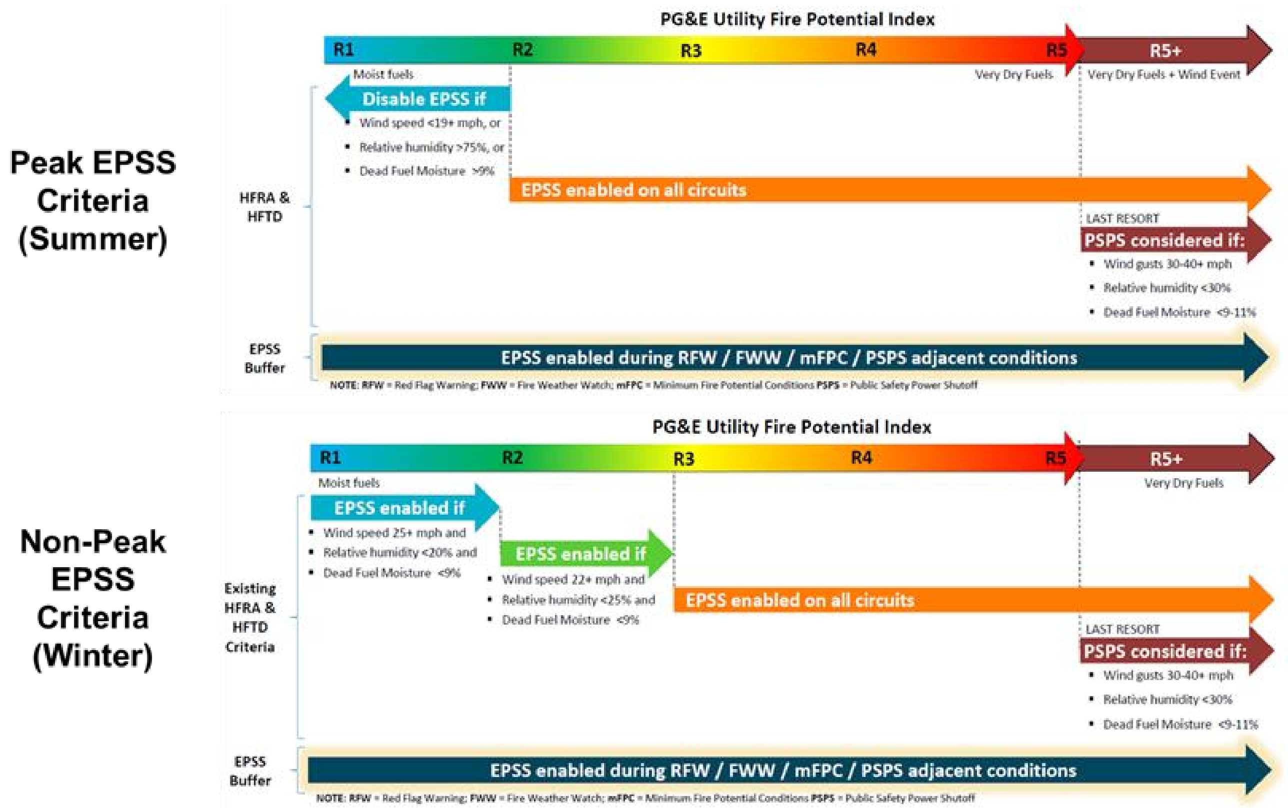
Managing Wildfire Risk continues to be a high priority for PG&E. As a top enterprise and safety risk since 2006, Wildfire Risk (without PSPS and EPSS) was included in the 2017 and 2020 RAMP proceedings. PG&E continues to update its analysis of Wildfire Risk and reports to the CPUC across RAMP reports, GRC proceedings, and its annual WMP.

While large fires are known in the historical record of California, in the last decade the state has experienced an increasing number of record-breaking wildfires. Exacerbating the situation, climate change is manifesting itself in extreme swings in weather. These exceptional temperatures, in turn, impact the relative humidity of the atmosphere, increasing the occurrence of vapor pressure deficit that is also linked to more severe fires. These conditions also pose a health risk to vegetation, increasing the potential for branch or tree failures impacting our assets (which creates potential sources of wildfire ignition).

Additionally, there has been a rise in population and urban development in the Wildland Urban Interface (WUI). These are areas where structures and other human development intermingles with undeveloped wildland. The WUI continues to expand in the state of California.

As the threat of wildfire persists in PG&E territory, PG&E has implemented operational mitigations throughout the year based on fire potential to manage the Wildfire Risk. Figure 1-4 represents PG&E's peak and non-peak enablement of such operational mitigations to maximize Wildfire Risk while minimizing customer impact. These operational mitigations, namely PSPS and EPSS, reduce the Wildfire Risk significantly during the year but introduce negative consequences, which will be described below. These negative consequences, along with the Wildfire Risk itself, is addressed through permanent risk reduction programs, which are described below. Of note, as PG&E calculates cost-benefit ratios associated with these permanent risk reduction programs, risk reduction benefits are represented as reduction to the Baseline Wildfire Risk, absent of operational mitigations, to stay true with the main intent of reducing Baseline Wildfire Risk.

FIGURE 1-4
EPSS ENABLEMENT CRITERIA



b. PSPS Risk

PG&E views PSPS as a mitigation of last resort to protect the people and communities that PG&E serves and to be used only when the risk of a severe wildfire is significant. Since PSPS's first use by PG&E in 2018, improvements have been made to the program to better target PSPS events, to minimize the scale of the event, and to reduce the negative consequences associated to these events. These improvements include additional sectionalizing of circuits to reduce the scale of PSPS outages, enhancements to FPI and Weather modeling to improve PSPS criteria, and system hardening to increase the resilience of the system/reduce the exposure to PSPS risk.

The PSPS risk is modeled utilizing a lookback approach. This approach applies the current PSPS criteria to weather conditions that PG&E's service territory has experienced in the past and identifies the locations where the PSPS criteria would be met. Circuit Protection

Zones (CPZ) that would have been impacted by the PSPS event are assessed to understand the number of customers on the CPZ, as well as downstream customers that would be impacted by the event. The count of impacted customers is used to calculate the consequence of each PSPS event, and the comparison of the PSPS criteria to historical weather conditions determines the frequency of PSPS events.

This approach has improved from the 2020 RAMP, as the reliability and indirect safety consequences of the PSPS risk are assessed independently of the Wildfire Risk.

c. EPSS Risk

Enhanced Powerline Safety Settings enablement presents a reliability risk when those settings are enabled across PG&E's service territory under heightened wildfire conditions. This reliability impact is primarily due to:

- An increased customer impact on outages occurring while EPSS is enabled, due to EPSS protection occurring at an upstream line recloser or circuit breaker versus a fuse when EPSS is disabled.
- Disabling automatic reclosing of protection devices, which is intended to avoid a fault condition creating an ignition.
- The unique patrol requirements following an outage while EPSS protection is enabled, which requires a full patrol of the zone of protection prior to restoration, and ultimately the duration of outage.

The heightened sensitivity of these settings reduces the likelihood that an ignition will initiate from a utility asset but does impact the reliability of circuits where these settings are enabled.

The EPSS risk is structured similarly to the Failure of Electric Distribution Overhead Assets (DOVHD) risk, as any outage during elevated fire conditions could be subject to an EPSS outage. Additionally, if an event that typically would result in a momentary outage occurs while EPSS is enabled, that event will result in a sustained outage due to the need to conduct an outage patrol.

One of the sets of outcomes for the DOVHD Bow Tie is events when EPSS is enabled, which is described in Exhibit (PG&E-4), Chapter 4, "Failure of Electric Distribution Overhead Assets". The difference in consequence associated to the DOVHD risk with EPSS and without EPSS determines the EPSS risk. The EPSS risk and methodology for calculating the risk is being piloted as part of the 2024 RAMP.

2. Risk Bow Ties

PG&E created several Bow Ties and risk scenarios to demonstrate: (1) PG&E's Baseline Wildfire Risk, (2) Post-PSPS/EPSS Wildfire Risk, (3) PSPS Consequence, (4) EPSS Consequence, and (5) the full Wildfire with PSPS and EPSS Risk. These scenarios and Bow Ties walk through the benefits of deploying PSPS and EPSS in reducing our overall Wildfire Risk, the reliability consequences from deploying PSPS and EPSS mitigations, and the net impact to Wildfire Risk on our system, considering deployment and its consequences. Additional details are described below.

- <u>Baseline Wildfire Risk</u>: Considers baseline risk without utilization of PSPS and EPSS operational mitigations. This is the Wildfire Risk that PG&E faces, based on its service territory and current assets. As additional system resilience mitigations are deployed, this baseline risk will decrease, as the expected frequency or consequence of wildfires will be reduced.
- <u>Post-PSPS/EPSS Wildfire Risk</u>: Considers the net resulting baseline risk while utilizing PSPS and EPSS operational mitigations as wildfire mitigation. For reference, this is what PG&E customers experience "day-to-day" as it relates to Wildfire Risk but is not a true reflection of the Wildfire Risk, given human operational controls involved. This also does not include the reliability consequences associated with the operational controls deployed.
- <u>PSPS Consequence</u>: Considers the negative impact of PSPS to customers. This is the risk that PG&E customers experience related to a "PSPS event," where lines are de-energized pre-emptively to an incoming weather event and conditions that can lead to a catastrophic fire.
- <u>EPSS Consequence</u>: Considers the negative impact of EPSS to customers. This is the risk that PG&E customers experience related to additional outages from the EPSS settings being enabled. These

settings disable automatic reclosing operations and make protection devices more sensitive to fault currents.

- Wildfire with PSPS and EPSS: Considers the net resulting risk of the wildfire plus the negative impacts of PSPS and EPSS. This is the risk PG&E customers experience collectively in the reduced Wildfire Risk but worsened reliability performance. The operation and impact of PSPS and EPSS is driven by the need to continually manage the significant safety risk that is posed by catastrophic wildfires.

Figure 1-5 below depicts PG&E's entire electric system for completeness, while Figure 1-6 represents PG&E's Transmission and Distribution (T&D) assets in HFTD+HFRA areas, where it represents 97 percent of the overall Wildfire Risk. Figure 1-5 represents the baseline Wildfire Risk across PG&E system territory and has a 2027 TY Baseline Wildfire Risk Value of $19,633 million. PG&E has individual breakouts of risk Bow Ties by each asset class and tranches located in its workpapers[4] for interested parties, simplified visuals provided below.

[4] Exhibit (PG&E-4), WP EO-WLDFR-2a and EO-WLDFR-2b.

FIGURE 1-5
WILDFIRE RISK BOW TIE – SYSTEMWIDE WILDFIRE RISK

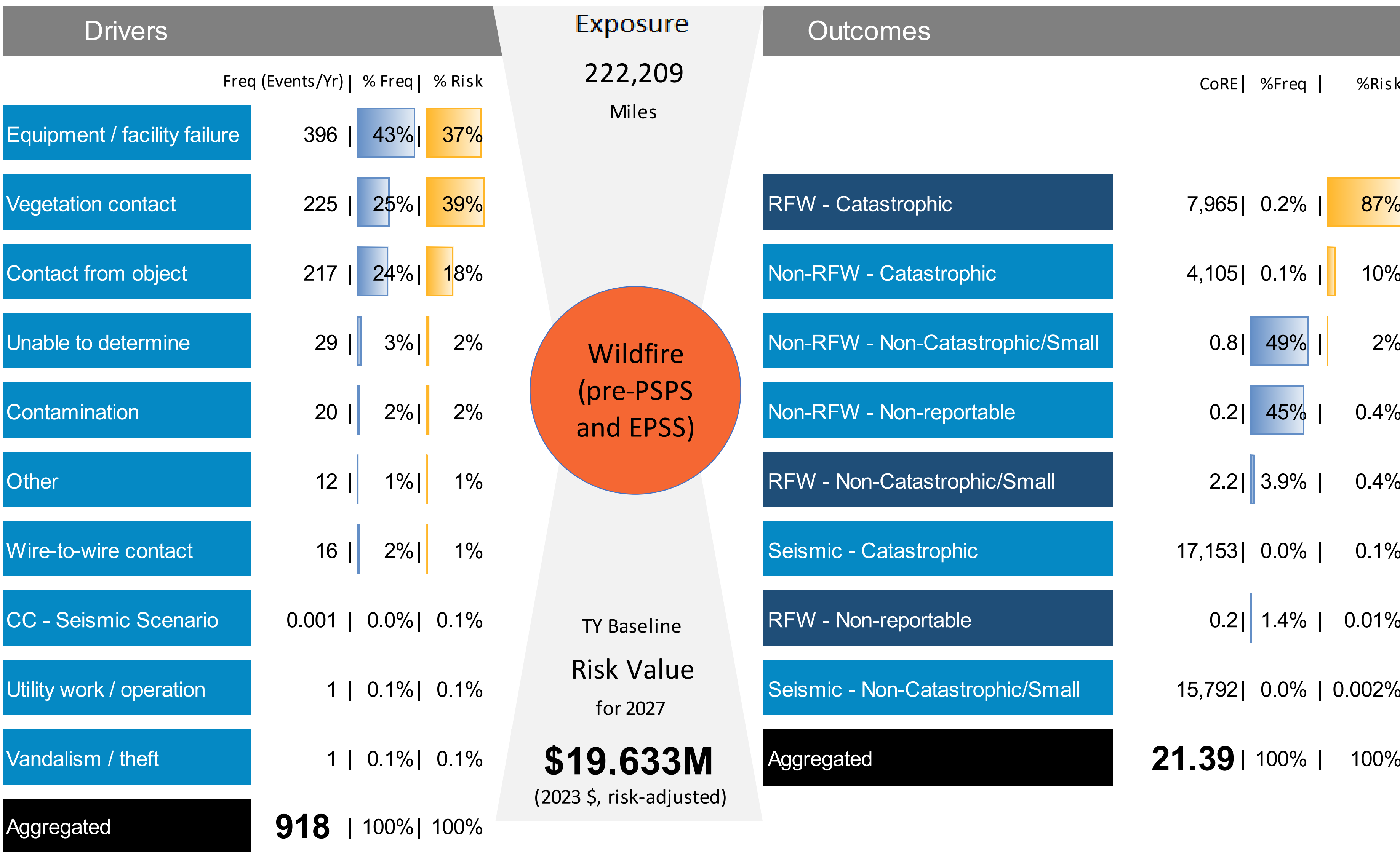
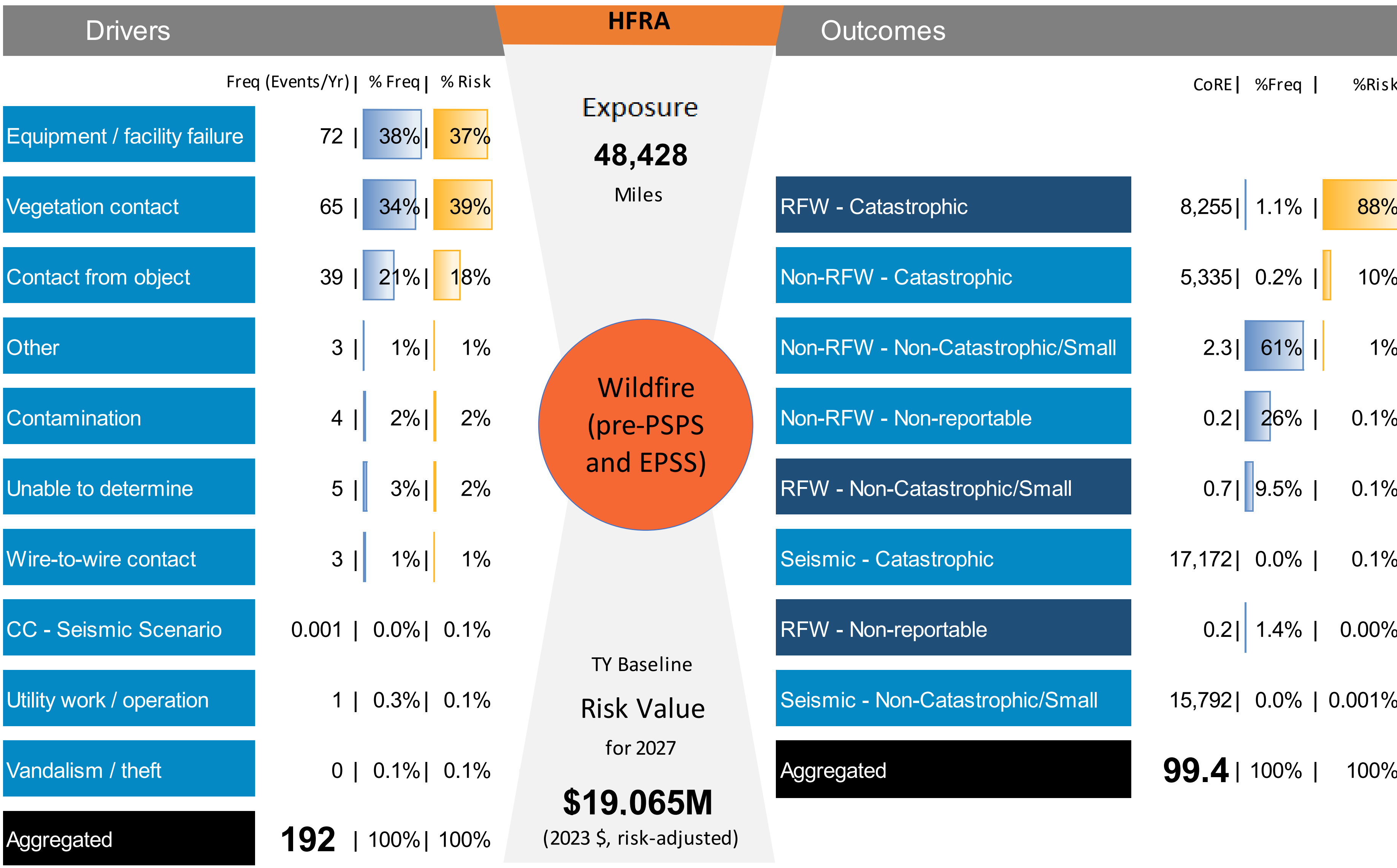


FIGURE 1-6
WILDFIRE RISK BOW TIE – T&D HFTD & HFRA ONLY

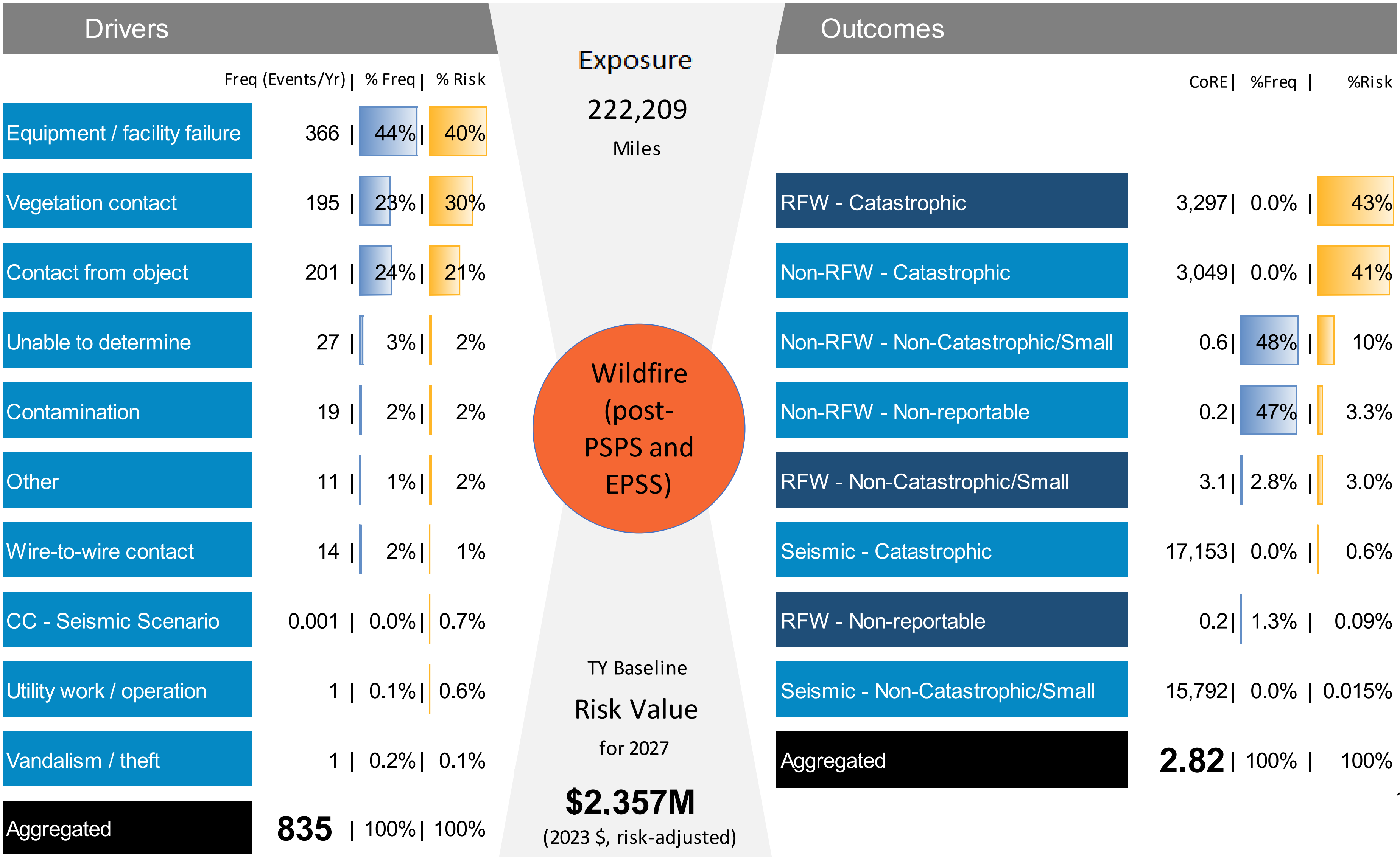


a. Post-PSPS/EPSS Wildfire Risk Bow Tie

Figure 1-7 illustrates PG&E's Wildfire Risk, post-PSPS and EPSS mitigations. The TY Baseline risk value for 2027 is $2,357 million, which is 88 percent lower than the overall Baseline Wildfire Risk ($19,633 million). This risk Bow Tie reflects the lowered frequency of risk events during the more catastrophic outcomes which substantially drives down the overall risk, operationally. The reduction of frequency for the highest consequence outcomes means that while the reduction in risk value is $17,276 million (see Figure 1-10 below), the overall reduction in frequency of ignitions is significantly less.

PSPS and EPSS are not intended to be permanent controls but rather address the Wildfire Risk while permanent solutions, such as system hardening, are deployed. To best reflect the impact that mitigations and controls will have related to this risk, they are assessed under the long-term intended operating condition of PSPS and EPSS no longer being required.

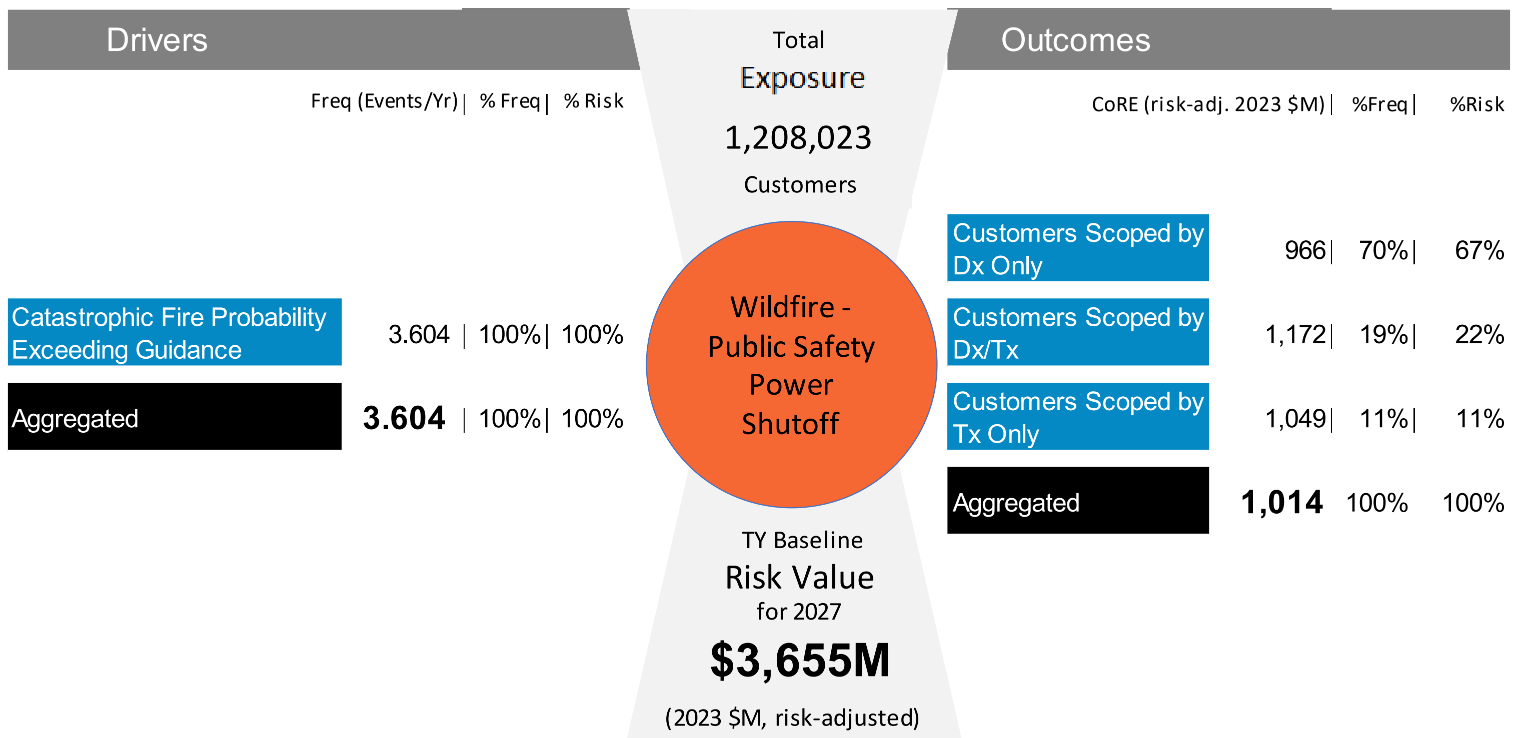
FIGURE 1-7
WILDFIRE RISK POST-PSPS/EPSS BOW TIE, PG&E SYSTEMWIDE



b. PSPS Consequence Risk Bow Tie

Figure 1-8 below demonstrates the negative impact, or risk, of PSPS in the Bow Tie. This risk Bow Tie reflects the annual expected frequency of 3.6 PSPS events per year, resulting in customer impacts totaling to a risk value of $3,655 million. The calculation is based on the current PSPS criteria applied against 2018-2022 weather scenarios. As a note, this is not reflective of historical actual events, but is based on a lookback of the size and scope of PSPS events, derived from current protocols with historical weather.

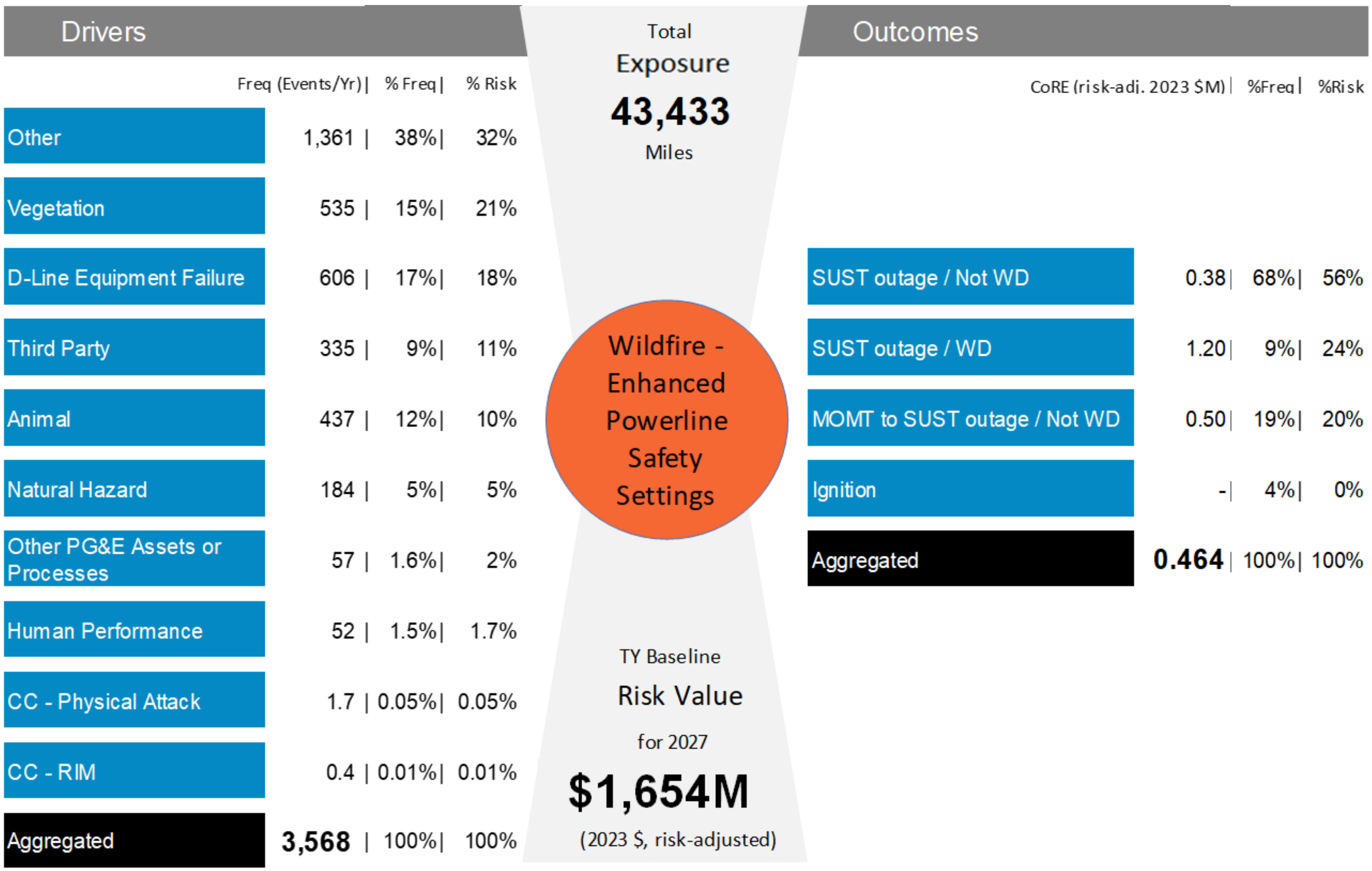
FIGURE 1-8
PSPS CONSEQUENCE BOW TIE



c. EPSS Consequence Risk Bow Tie

Figure 1-9 below illustrates the before and after impact of EPSS in the form of a risk Bow Tie. An EPSS outage is the result of the same drivers as the Failure of Electric Distribution Overhead Assets (DOVHD) risk, but which occurs when EPSS settings are enabled. The consequence of a DOVHD risk in which EPSS settings are enabled are higher than a typical DOVHD consequence. The calculation is based on the lookback analysis by applying the current EPSS criteria against the historical outages from 2017-2022, excluding 2021 due to the irregular results from the pilot EPSS Program. The difference in drivers is due to a unique makeup of outages that occur during EPSS activation, and the outcomes represent the incremental consequence associated to EPSS outages compared to non-EPSS outages. As a result of the EPSS settings being activated, the EPSS risk value is $1,654 million.

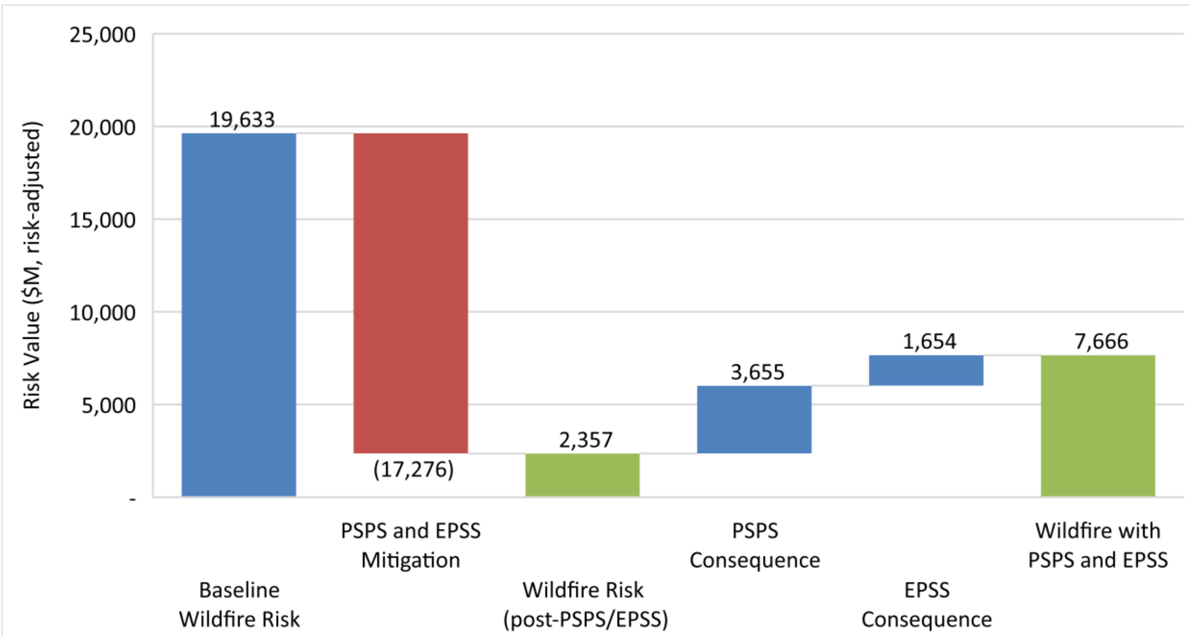
FIGURE 1-9
EPSS CONSEQUENCE BOW TIE



d. Wildfire with PSPS and EPSS

Figure 1-10 presents the starting 2027 Baseline Wildfire Risk, including physical mitigations, with the exception of PSPS and EPSS operational mitigations. Subsequently, it includes the benefits and negative impacts of PSPS and EPSS, collectively. The comprehensive risk value is $7,666 million.

FIGURE 1-10
2027 TY BASELINE - WILDFIRE WITH PSPS AND EPSS



e. Difference From 2020 Risk Bow Tie

- Wildfire: The 2024 RAMP Risk Bow Tie above differs from the Risk Bow Ties presented in the 2020 RAMP and TY2023 GRC in several important ways.
  - Refreshed Ignition Dataset and Inclusion of CPUC Non-reportable ignitions: PG&E refreshed the ignition data set to include 2015-2022 (three additional years). PG&E also included non-reportable CPUC ignitions into its Bow Tie model that increased the annualized ignitions from 450 to 923 ignitions per year. Although small, PG&E feels that these ignitions could

be precursors to larger ignitions and therefore found it appropriate to incorporate these events into our risk models;

  - Included PSPS and EPSS into the net impact to Wildfire: PG&E included risk bow tie breakdowns for PSPS and EPSS, as described in the section above; and
  - Expanded Exposure: Exposure to the Wildfire Risk was expanded to include Distribution Underground (UG), Secondary, and Service mileage. This was done in addition to the existing T&D OH circuit mileage historically presented.

- PSPS: The 2024 RAMP includes independent modeling of the PSPS risk. This approach meets the requirements outlined in Decision (D.) 21-11-009 and supports the assessment of the PSPS risk in conjunction with Wildfire. It enables better understanding of the full impacts and value provided by mitigation and control programs. PSPS modeling has also been improved from prior years through the application of the lookback study, providing additional insight into how PSPS guidance impacts customers.
- EPSS: The 2024 RAMP includes modeling of the impacts of EPSS, as shown by the net impact of EPSS on Failure of Electric Distribution Overhead Assets risk. This provides an understand and accounting for the reliability impacts associated to the EPSS wildfire mitigation. EPSS is new to PG&E's RAMP, and the quantification is being piloted in this report.

3. Exposure to Risk

a. Wildfire

Exposure for the Wildfire Risk is measured in circuit miles and totals to approximately 222,000 circuit miles in PG&E's electric distribution and transmission systems.

Table 1-2 demonstrates that 20.9 percent of our ignitions occur in HFTD+HFRA locations and account for 97 percent of our overall Wildfire Risk. 77 percent of our total Wildfire Risk is located within our primary distribution system.

TABLE 1-2
PG&E SYSTEM EXPOSURE (2027 TY BASELINE)

Line No.	Asset Class	Asset System	Total Exposure (Miles)	HFTD/HFRA (Miles)	% HFTD/HFRA Exposure	% Ignitions in HFTD/HFRA	% WF Risk in HFTD/HFRA
1	Distribution	UG	28,498	3,027	11%	0.2%	1%
2	Distribution	Primary OH	80,815	25,935	32%	17.3%	76%
3	Distribution	Secondary OH	16,157	2,771	17%	1.1%	3%
4	Distribution	Service OH	78,754	11,036	14%	1.0%	4%
5	Transmission	60/70 kilovolt (kV)	5,361	1,812	34%	0.7%	7%
6	Transmission	115 kV	5,942	1,737	29%	0.4%	5%
7	Transmission	230/500 kV	6,683	2,111	32%	0.1%	1%
8	Total		222,209	48,429		20.9%	97%

b. PSPS

PSPS exposure is measured as customers exposed to PSPS risk. The PSPS model is a lookback, which means it utilizes historical information at a CPZ-level to identify the aggregate consequence of events and their frequency. The exposure used in the model is approximately 1.2 million customers, based on the customers that are potentially impacted by this lookback.

c. EPSS

EPSS exposure is the mileage of overhead primary circuits that are EPSS capable. EPSS capable means the circuits could have EPSS enabled when the enablement criteria are met. The EPSS exposure used in the model is approximately 43,000 miles, estimated based on the number of miles that are EPSS capable.

4. Tranches

a. Wildfire

Wildfire Risk is separated by location and facility type, with further granularity established for the distribution risk based on the Wildfire Distribution Risk Model (WDRM). Altogether, this framing results in 50 tranches.

- <u>Location</u>: The first separation is by location, represented by HFTD/HFRA and non-HFTD/HFRA. In the prior RAMP report, PG&E focused on just the HFTDs, but as assessments have progressed, PG&E recognizes additional risk outside of the HFTD, generally around areas surrounding the HFTD that still pose risk. PG&E is in the process to petition the HFRA areas into updates to HFTD but deems these HFRA areas just as risky as HFTD and combines the miles together.

- Facility Types: The second separation is by the facility types of Distribution Overhead, Transmission Overhead, Substation, and Transmission and Distribution Underground. Given that these facility types are unique in design, PG&E separates the facilities in this manner.
- Distribution/Transmission: The third separation is within Distribution and Transmission, where further granularity was appropriate. For Distribution, PG&E created ten tranches by ranking CPZs based on mean Wildfire Risk score for each of the following: primary, secondary, and services, while UG has its own tranche. For Transmission, PG&E separates tranches by 60/70 kV, 115 kV, and 230/500 kV. Lastly PG&E separates out substation as its own tranche.

Table 1-3 summarizes PG&E's wildfire Bow Tie based on the approach to tranches described above. The majority of PG&E's Wildfire Risk lies within its primary distribution lines (76 percent) in HFTD/HFRA locations, which encompasses only 12 percent of our system line miles. PG&E's transmission OH in HFTD/HFRA locations poses the second highest risk, accounting for 13 percent of our Wildfire Risk over 3 percent of our system miles. Service lines on our distribution system poses the third highest risk at 4 percent (5 percent of our line system), followed by our secondary lines in HFTD/HFRA locations. HFTD/HFRA Primary distribution lines poses 10X greater risk than our secondary and service drops combined.

TABLE 1-3
TRANCHE LEVEL EXPOSURE STATISTICS

Tranche #	Tranche	Miles [(a)]	Frequency	LoRE	CoRE	Risk	Risk%	Risk/Mile
1	HFRA - Distribution - Primary - Tranche 1	434	1.7	0.0038	381.2	636	3.2%	1.5
2	HFRA - Distribution - Primary - Tranche 2	596	1.9	0.0031	337.8	627	3.2%	1.1
3	HFRA - Distribution - Primary - Tranche 3	718	4.2	0.0058	330.9	1,385	7.1%	1.9
4	HFRA - Distribution - Primary - Tranche 4	869	6.1	0.0070	286.1	1,754	8.9%	2.0
5	HFRA - Distribution - Primary - Tranche 5	1,088	7.7	0.0071	238.7	1,840	9.4%	1.7
6	HFRA - Distribution - Primary - Tranche 6	1,340	8.3	0.0062	206.2	1,721	8.8%	1.3
7	HFRA - Distribution - Primary - Tranche 7	1,765	10.0	0.0057	177.3	1,768	9.0%	1.0
8	HFRA - Distribution - Primary - Tranche 8	2,535	16.9	0.0067	105.9	1,788	9.1%	0.7
9	HFRA - Distribution - Primary - Tranche 9	3,930	31.4	0.0080	56.6	1,776	9.0%	0.5
10	HFRA - Distribution - Primary - Tranche 10	12,660	70.3	0.0055	22.2	1,558	7.9%	0.1
11	HFRA - Distribution - Secondary - Tranche 1	43	0.3	0.0062	280.3	76	0.4%	1.75
12	HFRA - Distribution - Secondary - Tranche 2	66	0.3	0.0052	248.0	85	0.4%	1.29
13	HFRA - Distribution - Secondary - Tranche 3	60	0.3	0.0045	244.3	66	0.3%	1.09
14	HFRA - Distribution - Secondary - Tranche 4	73	0.3	0.0042	210.8	66	0.3%	0.89
15	HFRA - Distribution - Secondary - Tranche 5	73	0.3	0.0042	174.8	53	0.3%	0.73
16	HFRA - Distribution - Secondary - Tranche 6	97	0.4	0.0038	148.4	55	0.3%	0.57
17	HFRA - Distribution - Secondary - Tranche 7	136	0.5	0.0034	131.0	60	0.3%	0.44
18	HFRA - Distribution - Secondary - Tranche 8	213	0.8	0.0039	76.9	64	0.3%	0.30
19	HFRA - Distribution - Secondary - Tranche 9	439	2.0	0.0046	41.0	83	0.4%	0.19
20	HFRA - Distribution - Secondary - Tranche 10	1,571	5.1	0.0033	15.4	79	0.4%	0.05
21	HFRA - Distribution - Service - Tranche 1	167	0.2	0.0014	314.6	75	0.4%	0.45
22	HFRA - Distribution - Service - Tranche 2	292	0.3	0.0012	279.4	96	0.5%	0.33
23	HFRA - Distribution - Service - Tranche 3	284	0.3	0.0010	275.1	79	0.4%	0.28
24	HFRA - Distribution - Service - Tranche 4	334	0.3	0.0010	237.4	76	0.4%	0.23
25	HFRA - Distribution - Service - Tranche 5	350	0.3	0.0010	196.8	65	0.3%	0.19
26	HFRA - Distribution - Service - Tranche 6	464	0.4	0.0009	167.2	67	0.3%	0.14
27	HFRA - Distribution - Service - Tranche 7	631	0.5	0.0008	147.6	71	0.4%	0.11
28	HFRA - Distribution - Service - Tranche 8	999	0.9	0.0009	86.6	77	0.4%	0.08
29	HFRA - Distribution - Service - Tranche 9	1,800	1.9	0.0010	46.2	87	0.4%	0.05
30	HFRA - Distribution - Service - Tranche 10	5,715	4.1	0.0007	17.4	72	0.4%	0.01
31	HFRA - Substation	196	0.7	0.0037	26.4	19	0.1%	0.10
32	HFRA - Transmission - 115 kV	1,737	3.8	0.0022	282.1	1,062	5.4%	0.61
33	HFRA - Transmission - 230/500 kV	2,111	0.7	0.0003	406.0	276	1.4%	0.13
34	HFRA - Transmission - 60/70 kV	1,812	6.5	0.0036	195.3	1,277	6.5%	0.70
35	HFRA - Underground	3,027	2.1	0.0007	59.9	126	0.6%	0.04
36	non-HFRA - Distribution - Primary - Tranche 1	1	0.5	0.3681	22.3	11	0.1%	8.20
37	non-HFRA - Distribution - Primary - Tranche 2	8	0.9	0.1039	22.3	20	0.1%	2.32
38	non-HFRA - Distribution - Primary - Tranche 3	14	1.0	0.0672	24.7	24	0.1%	1.66
39	non-HFRA - Distribution - Primary - Tranche 4	19	1.2	0.0648	20.0	24	0.1%	1.29
40	non-HFRA - Distribution - Primary - Tranche 5	21	1.2	0.0586	13.7	17	0.1%	0.81
41	non-HFRA - Distribution - Primary - Tranche 6	71	2.9	0.0403	11.7	34	0.2%	0.47
42	non-HFRA - Distribution - Primary - Tranche 7	117	4.0	0.0346	8.0	32	0.2%	0.28
43	non-HFRA - Distribution - Primary - Tranche 8	169	4.9	0.0291	6.3	31	0.2%	0.18
44	non-HFRA - Distribution - Primary - Tranche 9	576	14.1	0.0245	3.9	55	0.3%	0.10
45	non-HFRA - Distribution - Primary - Tranche 10	53,884	557.2	0.0103	0.4	249	1.3%	0.00
46	non-HFRA - Distribution - Secondary	13,385	66.1	0.0049	0.5	34	0.2%	0.00
47	non-HFRA - Distribution - Service	67,718	19.8	0.0003	0.2	4	0.0%	0.00
48	non-HFRA - Substation	801	3.9	0.0049	0.8	3	0.0%	0.00
49	non-HFRA - Transmission	12,326	24.0	0.0020	0.8	18	0.1%	0.00
50	non-HFRA - Underground	25,470	24.4	0.0010	0.5	12	0.1%	0.00
	Aggregated	**222,209**	**918.0**	**0.0041**	**21.39**	**19,633**	**100.0%**	**0.09**

(a) The exposure values are number of substations for Substation tranches.

b. PSPS

PSPS risk is tranched by customer classification which is described below:

- Extreme: Public Safety Partners; Provides Emergency Services
- Significant: Life Support customers or Medical Baseline customers who are low income
- Elevated: All other Medical Baseline, all other critical customer designations
- Regular: Regular customer

These classifications combine several customer factors to identify the significance of the impact an outage would have. These classifications help to allocate the risk of a PSPS event but are not used to change the overall expected consequence of a PSPS event.

TABLE 1-4
PERCENT EXPOSURE, RISK SCORE, AND PERCENT RISK BY TRANCHE

Line No.	Tranche	Exposure (%)	Safety Risk Value ($M)	Reliability Risk Value ($M)	Financial Risk Value ($M)	Aggregated Risk Value ($M)	Risk (%)
1	Regular	77%	19.4	1,577.0	25.9	1,622.4	44%
2	Elevated	18%	12.2	990.0	16.3	1,018.5	28%
3	Significant	5%	9.1	736.9	12.1	758.1	21%
4	Extreme	0%	3.1	248.7	4.1	255.8	7%
5	Total	100%	43.8	3,552.6	58.3	3,654.7	100%

c. EPSS

EPSS tranches are defined the same as the Failure of Electric Distribution Overhead Assets risk (DOVHD) tranches. The EPSS risk utilizes the same drivers as the DOVHD risk, and the reliability deciles that create the DOVHD tranches are also representative of EPSS risk. More details on the tranching for the DOVHD tranches can be found in Exhibit (PG&E-4), Chapter 4.

TABLE 1-5
PERCENT EXPOSURE, RISK SCORE, AND PERCENT RISK BY TRANCHE

Line No.	Tranche*	Exposure (%)	Safety Risk Value ($M)	Reliability Risk Value ($M)	Financial Risk Value ($M)	Aggregated Risk Value ($M)	Risk (%)
1	HFRA_Tranche_01	0.2%	1.51	86.3	0.075	87.9	5.3%
2	HFRA_Tranche_02	0.5%	1.56	101.9	0.086	103.6	6.3%
3	HFRA_Tranche_03	0.9%	0.70	59.9	0.056	60.6	3.7%
4	HFRA_Tranche_04	1.5%	0.91	70.3	0.058	71.2	4.3%
5	HFRA_Tranche_05	2.0%	0.47	46.1	0.066	46.6	2.8%
6	HFRA_Tranche_06	2.8%	0.97	59.8	0.074	60.8	3.7%
7	HFRA_Tranche_07	4.3%	1.12	73.0	0.117	74.2	4.5%
8	HFRA_Tranche_08	6.7%	0.72	62.1	0.120	63.0	3.8%
9	HFRA_Tranche_09	10.8%	1.19	85.4	0.172	86.7	5.2%
10	HFRA_Tranche_10	27.4%	0.90	74.9	0.287	76.1	4.6%
11	Non-HFRA_Tranche_01	0.1%	0.42	46.0	0.076	46.5	2.8%
12	Non-HFRA_Tranche_02	0.5%	1.99	147.7	0.083	149.7	9.1%
13	Non-HFRA_Tranche_03	1.0%	0.98	83.1	0.082	84.2	5.1%
14	Non-HFRA_Tranche_04	1.0%	0.81	89.5	0.075	90.4	5.5%
15	Non-HFRA_Tranche_05	1.4%	0.40	72.4	0.120	72.9	4.4%
16	Non-HFRA_Tranche_06	2.0%	0.62	108.1	0.116	108.9	6.6%
17	Non-HFRA_Tranche_07	2.4%	0.49	54.7	0.115	55.3	3.3%
18	Non-HFRA_Tranche_08	3.4%	0.79	81.5	0.170	82.5	5.0%
19	Non-HFRA_Tranche_09	5.8%	0.79	100.8	0.282	101.9	6.2%
20	Non-HFRA_Tranche_10	25.3%	1.17	129.1	0.708	131.0	7.9%
21	Total	100%	18.5	1632.6	2.939	1654.0	100%

Note: HFRA in this table refers to HFTD/HFRA.

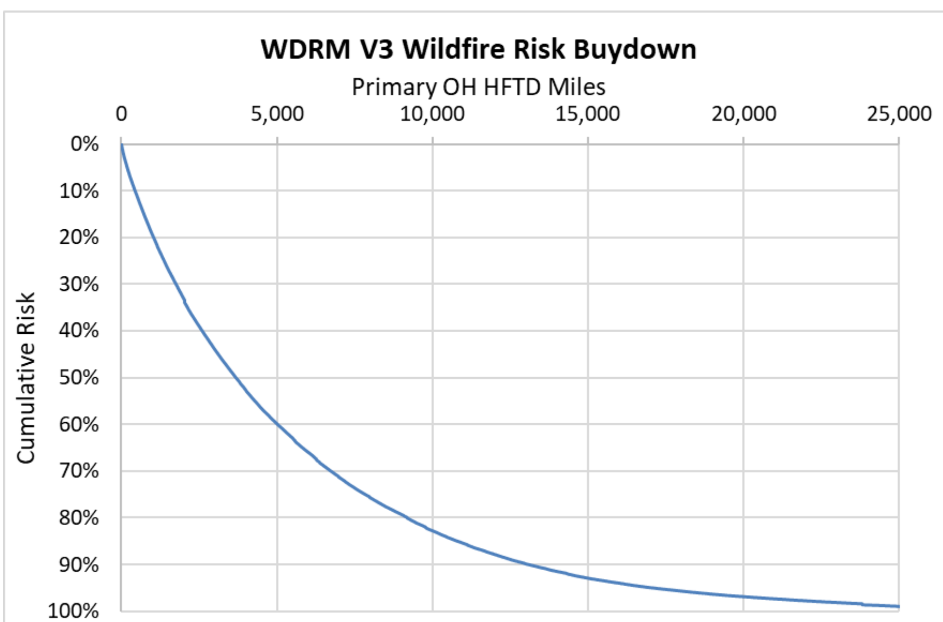
d. Feedback From February 2024, Pre-RAMP Workshop

PG&E presented the updated Wildfire Risk tranches at the 2024 RAMP Pre-filing workshop #1. PG&E presented a new tranching approach of using ten deciles of risk, moving away from the 5x5 Likelihood of a Risk Event (LoRE) and CoRE quintiles used in the TY2023 GRC. Per Safety Model Assessment Proceeding (S-MAP) requirement, row 14, "…the determination of Tranches will be based on how the risks and assets are managed by each utility…." In line with the S-MAP requirement and guidance received during the annual WMP process, PG&E has used the granular detail available in the Wildfire Risk models to prioritize work. Since the introduction of the WDRM v2 in 2021 and v3 in 2022, PG&E has systematically used the total risk score from the WDRM to guide and prioritize the workplans for each wildfire mitigation program. Instead of managing program purely from an asset management or LoRE perspective, risk reduction is based on the combination of LoRE times CoRE, represented in the units of risk. As such, workplans are based off risk buydown curves driven by the risk scores associated with circuit segments from the WDRM. For that reason, PG&E has transitioned its risk tranches in the form of deciles of risk.

The WDRM model breaks down PG&E's system into approximately 11,000 circuit segments, with approximately 3,600 circuit segments in HFTD/HFRA. In Figure 1-11, the cumulative risk and the number of miles of that risk are associated in a non-linear manner. For the top left-hand portion of the risk curve, a small number of miles represent the same amount of risk reduction as a much larger number of miles at the bottom right-hand portion of the risk curve.

PG&E's tranches presented in this RAMP represent the horizontal line divisions representing approximately 10 percent of the wildfire distribution risk sitting on its associated miles. Ultimately, the higher end of the risk buydown curve work activities can be performed, providing a higher risk reduction benefit. This yields the expectation of higher cost-benefit ratios.

FIGURE 1-11
WDRM RISK BUYDOWN CURVE



Based on this breakdown, PG&E demonstrates how activities in the highest risk locations from 2023-2026 change PG&E's TY baseline for 2027. In Table 1-6, the highest decile tranche initially has the highest risk per mile and descends as one moves down the tranches. Based on the activities expected from 2023-2026, the risk profile changes in the highest tranches, as work is already being performed there. This shows a lowered contribution to the overall risk and a reduction in the risk per mile in such tranches.

The approach provides additional insights on how the risk is being managed collectively, as PG&E plans the work through this risk buydown process. PG&E will never be able to solely work down a risk buydown exclusively, as it is generally not operationally feasible to do so. As an example, there are circuit segments upstream and downstream of high-risk circuit segments that may sit on a lower risk tranche. For the project to commence, work may need to occur in the adjacent, adjoining circuit segments to operationalize the risk benefit of PSPS and EPSS reliability reductions. This would be captured in the tranches where work is to be performed.

TABLE 1-6
HFRA – DISTRIBUTION – PRIMARY TRANCHES – RISK/MILE

		2023 Baseline			2027 TY Baseline		
Row Labels	Miles	Risk	% Risk	Risk/Mile	Risk	% Risk	Risk/Mile
HFRA - Distribution - Primary - Tranche 1	434	1,739	7.9%	4.0	636	3.2%	1.5
HFRA - Distribution - Primary - Tranche 2	596	1,718	7.8%	2.9	627	3.2%	1.1
HFRA - Distribution - Primary - Tranche 3	718	1,743	7.9%	2.4	1,385	7.1%	1.9
HFRA - Distribution - Primary - Tranche 4	869	1,729	7.9%	2.0	1,754	8.9%	2.0
HFRA - Distribution - Primary - Tranche 5	1,088	1,790	8.2%	1.6	1,840	9.4%	1.7
HFRA - Distribution - Primary - Tranche 6	1,340	1,740	7.9%	1.3	1,721	8.8%	1.3
HFRA - Distribution - Primary - Tranche 7	1,765	1,740	7.9%	1.0	1,768	9.0%	1.0
HFRA - Distribution - Primary - Tranche 8	2,535	1,755	8.0%	0.7	1,788	9.1%	0.7
HFRA - Distribution - Primary - Tranche 9	3,930	1,699	7.7%	0.4	1,776	9.0%	0.5
HFRA - Distribution - Primary - Tranche 10	12,660	1,517	6.9%	0.1	1,558	7.9%	0.1

Note: HFRA in this table refers to HFTD/HFRA.

5. Drivers and Associated Frequency

a. Wildfire

PG&E utilizes both CPUC-reportable and non-reportable ignitions as the frequency of the risk event to capture more data as it relates to ignition drivers. For context, the CPUC requires utilities to report ignitions involving their equipment that meet the following criteria, per D.14-02-015:

1) A self-propagating fire of material other than electrical and/or communication facilities;
2) The resulting fire traveled greater than one linear meter from the ignition point; and
3) The utility has knowledge that the fire occurred.

The frequency of wildfires is assessed across 10 risk drivers. Equipment failure is the most frequent risk driver, consisting of 38 percent of the events. Vegetation contact is the second most frequent event, representing 34 percent of the frequency, but 39 percent of the total risk. This is due to the vegetation drivers being more frequently associated to high consequence outcomes. Each driver and its associated estimated frequency for 2027 test-year baseline are discussed below.

- <u>Equipment Failure (38 percent of frequency)</u>: This driver is defined as events where failure of a PG&E asset, such as a conductor, arrester, insulator, breaker, transformer, etc., caused an ignition. Conductor and connection device damage or failure accounts for roughly 47 percent of all equipment ignitions.
- <u>Vegetation Contact (34 percent of frequency)</u>: This driver is defined as events where trees, tree limbs, and other vegetation come in contact with a PG&E asset, resulting in an ignition. Vegetation branch and trunk failure account for 80 percent of all vegetation ignitions.
- <u>Contact from Object (21 percent of frequency)</u>: This driver is defined as events where objects come into contact with PG&E line equipment and create an ignition. This includes animal/bird contact,

mylar balloons, and vehicles. Animal contact accounts for 10 percent of all ignitions systemwide.

- Unable to Determine (3 percent of frequency): This driver considers events associated with PG&E assets which led to an ignition, but where PG&E is unable to establish the main driver of the ignition.
- Contamination (2 percent of frequency): This driver represents contamination events, which includes ignitions caused by battery assets and contaminated insulators.
- Other (1 percent of frequency): This driver includes failure events without known causes.
- Wire-to Wire Contact (1 percent of frequency): This driver includes ignitions caused by wire-to-wire contact, commonly known as line slap.
- Seismic Scenario (<1 percent of frequency): This driver reflects failure events caused by seismic activity. This risk is described further in Exhibit (PG&E-2), Chapter 3 of this report.
- Utility Work/Operation (<1 percent of frequency): This driver includes activities around utility processes.
- Vandalism/Theft (<1 percent of frequency): This driver reflects theft or vandalism from outside parties.

Table 1-7 details the annualized frequency of ignitions in HFTD/HFRA locations and the associated contribution to the overall Wildfire Risk.

TABLE 1-7
BOW TIE DRIVER FREQUENCY AND RISK – T&D HFTD/HFRA ONLY

Line No.	Ignition Driver	# Ignitions	% Ignitions	% WF Risk
1	Equipment/facility failure	72.1	37.6%	36.5%
2	Vegetation contact	64.8	33.8%	38.9%
3	Contact from object	39.3	20.5%	18.1%
4	Unable to determine	5.4	2.8%	2.3%
5	Contamination	4.0	2.1%	1.7%
6	Wire-to-wire contact	2.8	1.5%	1.2%
7	Other	2.6	1.4%	0.9%
8	Utility work/operation	0.5	0.3%	0.1%
9	Vandalism/theft	0.2	0.1%	0.1%
10	CC – Seismic Scenario	0.0	0.0%	0.1%
11	Total HFTD/HFRA Ignitions	191.7		

Table 1-8 provides additional visibility into the systems where our ignition drivers occur. 83 percent of all ignitions in HFTD/HFRA occur on our primary distribution lines and are driven by equipment failure (31 percent), vegetation (30 percent), and contact ignitions (17 percent). Values in this table represent percentages of all ignitions in HFTD/HFRA. Our transmission ignitions account for 11 percent of HFTD/HFRA ignitions. Transmission ignitions are driven by equipment and contact ignitions.

TABLE 1-8
BOW TIE TRANCHE DRIVER % IGNITION – TY 2027 BASELINE

Line No.		Asset System	Total HFTD/HFRA Ignitions	Equipment Ignitions	Vegetation Ignitions	Contact Ignitions	Remaining Ignitions
1	Distribution	UG	2.1	1% (1.7)	0% (0.1)	0% (0.3)	0% (0)
2	Distribution	Primary OH	158.4	31% (58.8)	30% (56.7)	17% (33.3)	5% (9.6)
3	Distribution	Secondary OH	10.3	2% (3.9)	2% (3.6)	1% (2.1)	0% (0.6)
4	Distribution	Service OH	9.3	2% (3.5)	2% (3.4)	1% (1.9)	0% (0.5)
5	Transmission	60/70 kV	6.5	1% (2.2)	0% (0.9)	1% (2.3)	1% (1.1)
6	Transmission	115 kV	3.8	1% (1.3)	0% (0.1)	1% (2)	0% (0.4)
7	Transmission	230/500 kV	0.7	0% (0.2)	0% (0)	0% (0.1)	0% (0.4)
8	T&D	Substation	0.7	0% (0.5)	0% (0)	0% (0.1)	0% (0.1)
9	Total		191.8	38% (72.1)	34% (64.8)	22% (42.1)	7% (12.7)

b. PSPS

The PSPS bow tie has a single driver, Catastrophic Fire Probability Exceeding Guidance. This driver represents environmental and meteorological conditions exceeding the established PSPS guidance. The guidance has been set to capture the conditions where the largest historical fires occurred, to avoid future ignitions under similar conditions. This driver assumes that when the PSPS guidance thresholds are met that the decision will be made to initiate a PSPS event and de-energize the effected circuit protection zones.

c. EPSS

EPSS drivers are defined the same as the Failure of Electric Distribution Overhead Assets risk (DOVHD) drivers. The EPSS risk has been quantified as difference between the DOVHD risk with and without EPSS. More details on the drivers for the DOVHD risk can be found in Exhibit (PG&E-4), Chapter 4.

The distribution of drivers is different from the DOVHD risk, as the frequency of drivers that occur during EPSS activation is different than what occurs when EPSS is not activated.

The largest change is associated to the Other driver. The Other driver accounts for 38 percent of the frequency of EPSS-related outages, compared to 26.2 percent of the DOVHD outages. The Other driver consists of outages where a cause cannot be identified, which increases under EPSS conditions as momentary outages are converted into sustained outages due to the increased sensitivity of the protection settings.

6. Climate Adaptation Vulnerability Assessment Results

PG&E designed the Climate Adaptation Vulnerability Assessment (CAVA) to be consistent with the CPUC's Final Ruling on Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Change Adaptation (Rulemaking 18-04-019). The methodology outlined by D.20-08-046 requires utilities to perform an assessment of all assets, operations, and services that will be impacted by future risks from climate change related to changes in temperatures, precipitation and flooding, sea level rise, wildfire, and drought-driven subsidence. At a broader level, PG&E's CAVA assesses how climate change will impact the long-term likelihood of all wildfires to the Company's assets, operations, and services; however, it does not specifically consider the impacts of climate change to utility-caused ignitions, nor does it address the period covered in this filing.

7. Cross-Cutting Factors

A cross-cutting factor is a driver, component of a driver, or a consequence multiplier that impacts multiple risks. PG&E is presenting seven cross-cutting factors in the 2024 RAMP. The cross-cutting factors that impact the Wildfire Risk are shown in Table 1-9.

TABLE 1-9
CROSS-CUTTING FACTOR SUMMARY

Line No.	Cross-Cutting Factor	Impacts Likelihood	Impacts Consequence
1	Climate Change	Yes*	Yes
2	Cyber Attack	Yes*	Yes*
3	Emergency Preparedness and Response	No	Yes*
4	Information Technology Asset Failure	Yes*	Yes*
5	Physical Attack	Yes	Yes*
6	Records and Information Management	Yes*	No
7	Seismic	Yes	Yes

Yes The cross-cutting factor has been quantified in the model.

Yes* The cross-cutting factor does influence the baseline risk but has not been quantified in the model, or the cross-cutting factor may influence the baseline risk but further study is needed.

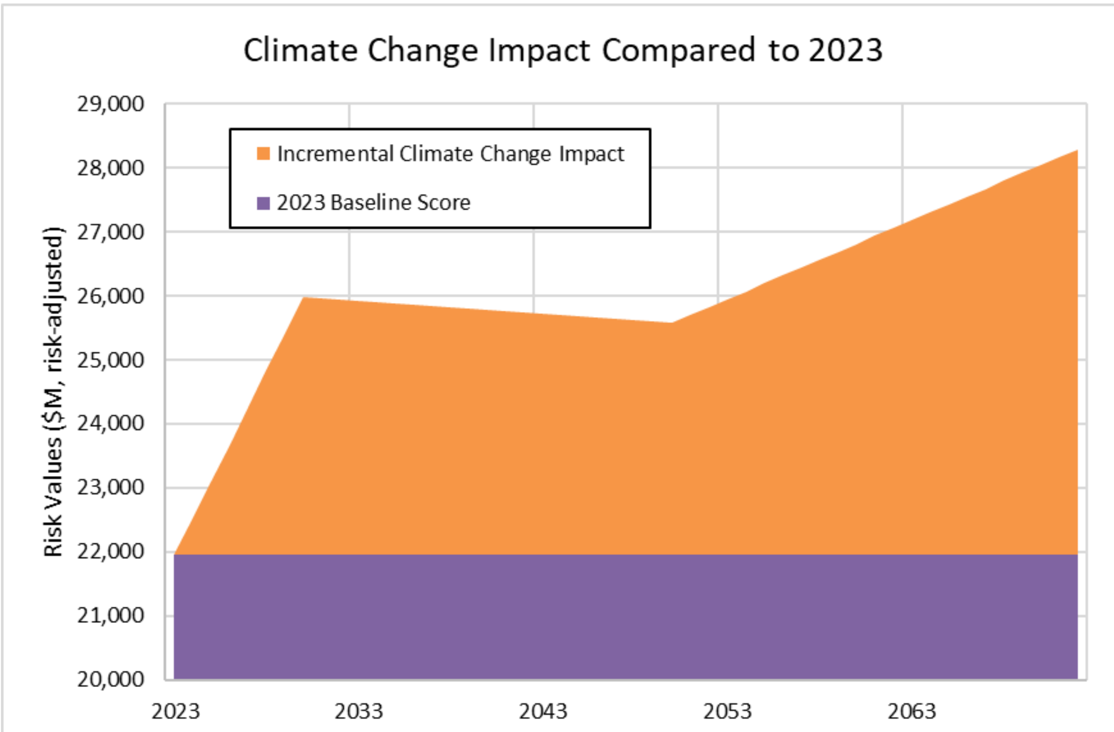
No The cross-cutting factor does not meaningfully influence the baseline risk.

A description of the cross-cutting factors and the mitigations and controls that PG&E is proposing to mitigate the cross-cutting factors is in Exhibit (PG&E-2), Chapter 3.

a. Climate Change

Climate change is incorporated into the modeling of the Wildfire Risk as a climate change factor that is applied to the risk. This represents the increased stress that climate change is likely to have on the system. Increased temperature and drought conditions can affect the health of vegetation near lines and alter the fuel mix. Increased heat puts an additional strain on PG&E assets through increased load and limitations to heat dissipation. These conditions can increase the frequency and consequence of potential ignition events.

FIGURE 1-12
RISK SCORE – RFW CLIMATE IMPACT MODEL



b. Physical Attack

Vandalism of assets can lead to asset failure events, resulting in an outage or ignition. These types of ignitions are identified in the ignitions data and are included in the risk bow tie as a frequency subdriver.

c. Seismic

PG&E's service territory is in an active seismic zone. As such, all PG&E assets are subject to the potential for damage from ground shaking and related ground failure that ranges from minor to catastrophic from a single event. Due to a lack of historical 7.0+ seismic events in PG&E service territory, PG&E leveraged simulated data from the SERA model. The three earthquake scenarios considered are:

- Hayward Fault (North & South Segments) (M 6.9) – Return period: 104 years;

- San Andreas Fault (Peninsula Segment) (M 7.2) – Return period: 125 years; and
- Rodger's Creek Fault (M 7.0) – Return period: 108 years.

The SERA model ingests PG&E system configurations and determines the number of damages that would occur, based on the earthquake scenarios described above. Based on this damage assessment, PG&E has calculated the number of ignitions that would have occurred, leveraging historical outage-to-ignition data.

8. Consequences

a. Wildfire

The consequence of the Wildfire Risk event Bow Tie is considered along two dimensions: Fire Size and RFW days. Fire Size is assessed based on the scale or consequence of an ignition, which are described below.

- OEIS Catastrophic: Defined as a CPUC-reportable fire that burns > 5,000 acres, or destroys > 500 structures, or results in a fatality. This definition aligns with the definition of a catastrophic wildfire provided by OEIS in the guidelines for the 2023–2025 WMP.
- Non-Catastrophic/Small:
  - Destructive: Defined as a CPUC Reportable fire that burns 300 or more acres and destroys no less than 100 structures.
  - Large: Defined as a CPUC-reportable fire that burns 300 or more acres, but destroys < 100 structures.
  - Small: Defined as a CPUC-reportable fire that burns fewer than 300 acres.
- Non-Reportable Ignitions: Defined as fires that do not meet CPUC reporting criteria and/or are not associated with utility assets.

Of the 192 ignitions that occur under the baseline conditions in HFTD/HFRA, 1.3 percent of those ignitions have the potential of leading to a catastrophic wildfire. This 1.3 percent (2.5 annualized catastrophic ignitions) are estimated to account for 98.4 percent of our Wildfire Risk in HFTD/HFRA locations.

TABLE 1-10
FIRE CATEGORIZATION AND NUMBER OF IGNITIONS – HFTD/HFRA ONLY

Line No.	Fire Categorization	Total Ignitions	Ignitions	Wildfire Risk Likelihood
1	Catastrophic	2.5	1.3% (2.5)	98.4%
2	Non-Catastrophic/Small	136.1	70.9% (136)	1.5%
3	Non-Reportable	53.6	27.9% (53.5)	0.05%
4	Total	192.2		

RFW conditions are a forecast warning issued by the NWS in the United States to inform the public, firefighters, and land management agencies that conditions are ideal for wildland fire combustion and rapid spread. The consequences from ignition events are higher under RFW conditions. PG&E's risk calculations highlight that 88 percent of the total Wildfire Risk can be traced to ignitions on RFW days in HFTD/HFRA locations that lead to catastrophic fires. Only 12 percent of ignitions are normalized to occur during RFW days. PG&E's decision to invest in PSPS and EPSS mitigation actions targets reducing ignitions when RFW conditions occur. To better understand and address these high consequence events, PG&E continues to invest in situational awareness programs, such as weather stations, wildfire cameras, satellite monitoring, and the hazard awareness warning center (HAWC) to improves its ability to predict and to respond to dangerous weather conditions like RFW conditions.

Table 1-11 demonstrates the frequency associated with ignitions divided by RFW based on their contribution to Wildfire Risk.

TABLE 1-11
RISK EVENT IGNITIONS AND CONSEQUENCES – T&D HFTD/HFRA

Line No.	RFW Status and Fire Type	# Ignitions	% Ignitions	% WF Risk
1	RFW – Catastrophic	2.1	1.1%	88.4%
2	RFW – Non-Catastrophic/Small	18.2	9.5%	0.1%
3	RFW – Non-reportable	2.7	1.4%	0.0%
4	Non-RFW – Catastrophic	0.4	0.2%	10.0%
5	Non-RFW – Non-Catastrophic/Small	117.9	61.4%	1.4%
6	Non-RFW – Non-reportable	50.9	26.5%	0.1%
7	Seismic – Catastrophic	0.0	0.0%	0.1%
8	Seismic – Non-Catastrophic/Small	0.0	0.0%	0.0%

The full allocation of risk to consequence dimensions is described in Table 1-12. Model attributes are described in Exhibit (PG&E-2), Chapter 2.

TABLE 1-12
BASELINE WILDFIRE RISK EVENT CONSEQUENCES – TY BASELINE 2027

	CoRE	%Freq	%Risk	Freq	Natural Units Per Event				Expected Loss per Year (2023 $M)				Attribute Risk Score			
					Safety EF/event	Indirect Safety EF/event	Electric Reliability MCMI/event	Financial $M/event	Safety $M/yr	Indirect Safety $M/yr	Electric Reliability $M/yr	Financial $M/yr	Safety $M/yr	Indirect Safety $M/yr	Electric Reliability $M/yr	Financial $M/yr
RFW - Catastrophic	7,965.3	0.23%	87%	2.1	9.32	0.37	63.64	1,245.2	304.43	12.21	432.59	2,670.07	1,722.1	20.3	729.1	14,607.8
Non-RFW - Catastrophic	4,104.9	0.05%	10%	0.5	2.21	0.20	35.47	681.6	16.44	1.52	54.91	332.85	92.6	2.5	91.6	1,817.9
Non-RFW - Non-Catastrophic/Small	0.8	49.10%	2%	450.7	0.00	0.00	0.08	0.1	5.94	2.99	119.99	48.39	6.1	3.1	124.0	237.9
Non-RFW - Non-reportable	0.2	45.32%	0%	416.1	-	0.00	0.06	0.0	-	2.08	77.64	1.45	-	2.1	77.7	1.5
RFW - Non-Catastrophic/Small	2.2	3.91%	0%	35.9	0.00	0.00	0.13	0.4	0.76	0.27	15.13	14.12	0.9	0.3	15.6	62.1
Seismic - Catastrophic	17,153.0	0.00%	0%	0.0	15.21	0.76	128.58	2,530.4	0.21	0.01	0.36	2.24	1.2	0.0	0.7	13.3
RFW - Non-reportable	0.2	1.38%	0%	12.7	-	0.00	0.06	0.0	-	0.06	2.37	0.04	-	0.1	2.4	0.0
Seismic - Non-Catastrophic/Small	15,792.2	0.00%	0%	0.0	-	0.76	128.58	2,530.4	-	0.00	0.01	0.06	-	0.0	0.0	0.3
Aggregated	21.39	100%	100%	918.0	0.02	0.00	0.24	3.3	327.78	19.16	703.00	3,069.23	1,823.0	28.4	1,041.1	16,740.7

b. PSPS

The outcomes of the PSPS bow tie represent the scope of the potential PSPS event. They have been segmented by the types of assets that could be impacted by a PSPS event. This scoping is done to help understand what mitigations will address the specific outcomes, as distribution focused mitigations will not fully mitigate transmission PSPS events. The PSPS outcomes are:

- <u>Customers Scoped by Dx Only</u>: This outcome includes those customers who are only scoped for PSPS on distribution circuits or segments. These customers represent 70 percent of the expected frequency of events and represent 67 percent of the risk.
- <u>Customers Scoped by Tx Only</u>: This outcome includes those customers who are scoped for PSPS due to an upstream transmission line. These customers are not in the footprint of the event but are impacted as they are no longer able to be served power through the transmission line. These customers represent 11 percent of the events and 11 percent of the risk.
- <u>Customers Scoped by Tx and Dx</u>: This outcome includes customers who are impacted by both a Transmission and Distribution line being impacted by the PSPS event. These customers represent 19 percent of the frequency of events and represent 22 percent of the risk.

TABLE 1-13
PSPS RISK EVENT CONSEQUENCES – TY BASELINE 2027

					Natural Units Per Event			CoRE (risk-adjusted 2023 $)			Expected Loss per Year (2023 $M)			Attribute Risk Score (2023 $M/yr, risk-adjusted)		
	CoRE	%Freq	%Risk	Freq	Indirect Safety EF/event	Electric Reliability MCMI/event	Financial $M/event	Indirect Safety $M	Electric Reliability $M	Financial $M	Indirect Safety $M/yr	Electric Reliability $M/yr	Financial $M/yr	Indirect Safety	Electric Reliability	Financial
Customers Scoped by Dx Only	966	70%	67%	2.5	0.56	182.45	12.02	12	939	15	21	1,465	30	29	2,379	39
Customers Scoped by Dx/Tx	1,172	19%	22%	0.7	0.67	221.25	14.58	14	1,139	19	7	482	10	10	782	13
Customers Scoped by Tx Only	1,049	11%	11%	0.4	0.60	198.13	13.05	13	1,020	17	4	241	5	5	392	6
Aggregated	1,014	100%	100%	3.6	0.58	191.52	12.62	12	986	16	32	2,188	45	44	3,553	58

c. EPSS

The outcomes for the EPSS risk are a subset of the outcomes for the DOVHD risk, including only the incremental impact of outages under EPSS conditions. A description of the Asset Failure/Third Party, WD/Not WD, and Ignition/No Ignition can be found in the DOVHD risk chapter, Exhibit (PG&E-4), Chapter 4.

The EPSS specific outcomes are the Sustained Outage outcome and the Momentary to Sustained Outage. They are described below.

- Sustained Outage: The Sustained Outage outcome are outages that would have occurred whether EPSS was enabled or not enabled on a circuit. The only change to these outages is the extended duration associated to the patrol and re-energization standards that are a part of the EPSS Program. The outcomes that include Sustained Outage only account for the reliability consequence attributable to EPSS and does not include the consequence of the outage under non-EPSS conditions.
- Momentary to Sustained Outage: The Momentary to Sustained Outage outcome are outages that would have been momentary had EPSS settings not been enabled. These outages are not part of the DOVHD risk as they do not pose a reliability consequence without the enablement of EPSS but occur due to the enhanced sensitivity of EPSS protection settings. The full consequence of the outage is included for these outcomes, as they would not occur if EPSS is not enabled.

TABLE 1-14
EPSS RISK EVENT CONSEQUENCES – TY BASELINE 2027

					Natural Units Per Event				CoRE (risk-adjusted 2023 $)				Natural Units per Year				Attribute Risk Score			
	CoRE	%Freq	%Risk	Freq	Safety EF/event	Indirect Safety EF/event	Electric Reliability MCMI/event	Financial $M/event	Safety $M	Indirect Safety $M	Electric Reliability $M	Financial $M	Safety EF/yr	Indirect Safety EF/yr	Electric Reliability MCMI/yr	Financial $M/yr	Safety $M/yr	Indirect Safety $M/yr	Electric Reliability $M/yr	Financial $M/yr
SUST outage / Not WD	0.38	68%	56%	2,411.8	-	0.00017	0.12	-	-	0.0027	0.38	-	-	0.42	289.75	-	-	6.42	918.52	-
SUST outage / WD	1.2	9%	24%	324.8	-	0.00118	0.37	-	-	0.02	1.19	-	-	0.38	121.58	-	-	5.84	385.42	-
MOMT to SUST outage / Not WD	0.5	19%	20%	680.0	0.00002	0.00059	0.15	0.00	0.0003	0.01	0.48	0.0043	0.01	0.40	103.67	2.94	0.17	6.07	328.62	2.94
Ignition	-	4%	0%	152.0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Aggregated	0.464	100%	100%	3,568.5	0.000003	0.00034	0.14	0.00	0.00005	0.01	0.46	0.0008	0.01	1.20	515.00	2.94	0.17	18.33	1,632.56	2.94

d. Potential Environmental and Social Justice Consequences

PG&E selected Baseline Wildfire Risk as an Environmental and Social Justice (ESJ) pilot study plan (PSP) pilot risk for Action Items #1 and #6.[5] To address these Action Items, PG&E developed a methodology for determining the impact to Disadvantaged and Vulnerable Communities (DVC), as defined in D.22-12-027, and used this methodology to calculate the consequences, mitigation benefits, and total costs of mitigations associated with DVCs.

1) Methodology

The Baseline Wildfire Risk utilized a percentage-based approach to determine impacts of the risk to DVCs. To determine the DVC percentage, the DVC population was determined at each circuit segment and divided by the total population. This resulting percentage was multiplied by the consequences of each tranche to determine the impacts of the risk on the DVC. Mitigations with non-specific locations in a tranche were assumed to be partially applied to the DVC as well; thus, the percentage from the tranche analysis was carried through to the mitigation benefits and costs.

2) Tranches and Consequence

Table 1-15 provides the tranche analysis for DVCs for Wildfire, excluding PSPS and EPSS. There are 42 Wildfire Risk tranches for the distribution system that deliver power to the DVC community but those were aggregated into 20 tranche groups in the table. The Baseline Wildfire Risk is provided for each distribution tranche group, along with the associated DVC Risk and Frequency of ignitions.

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5 Refer to Exhibit (PG&E-2), Chapter 7 for more details on the ESJ PSP.

TABLE 1-15
DVC TRANCHE & CONSEQUENCE

Line No.	Distribution Tranche Group*	% DVC Customers	Baseline WF Risk	DVC Risk	Non-DVC Risk	% DVC Risk
1	HFRA – Distribution – Tranche 1	23%	786	226	560	29%
2	HFRA – Distribution – Tranche 2	18%	808	210	599	26%
3	HFRA – Distribution – Tranche 3	35%	1,530	638	892	42%
4	HFRA – Distribution – Tranche 4	32%	1,896	740	1,155	39%
5	HFRA – Distribution – Tranche 5	28%	1,959	709	1,250	36%
6	HFRA – Distribution – Tranche 6	31%	1,843	641	1,202	35%
7	HFRA – Distribution – Tranche 7	20%	1,899	529	1,370	28%
8	HFRA – Distribution – Tranche 8	22%	1,930	593	1,337	31%
9	HFRA – Distribution – Tranche 9	15%	1,946	414	1,532	21%
10	HFRA – Distribution – Tranche 10	13%	1,709	338	1,371	20%
11	Non-HFRA – Distribution – Tranche 1	87%	12	3	9	23%
12	Non-HFRA – Distribution – Tranche 2	3%	20	2	18	10%
13	Non-HFRA – Distribution – Tranche 3	64%	24	7	17	29%
14	Non-HFRA – Distribution – Tranche 4	27%	25	7	17	30%
15	Non-HFRA – Distribution – Tranche 5	17%	17	6	11	35%
16	Non-HFRA – Distribution – Tranche 6	56%	34	12	22	36%
17	Non-HFRA – Distribution – Tranche 7	39%	33	9	24	27%
18	Non-HFRA – Distribution – Tranche 8	21%	31	10	22	31%
19	Non-HFRA – Distribution – Tranche 9	16%	56	12	44	21%
20	Non-HFRA – Distribution – Tranche 10	31%	260	106	154	41%
21	Grand Total	29%	16,818	5,213	11,604	31%

Note: HFRA in this table refers to HFTD/HFRA.

3) Mitigation

Two programs and their DVC benefits are described below:

- PSPS and EPSS: PSPS and EPSS target HFTD/HFRA locations, and these tranches are only included in the analysis and table below. The overall Wildfire Risk reduction per tranche was multiplied by the % DVC Wildfire Risk from Table 1-15 to estimate DVC wildfire risk reduction. There are risk reduction benefits mapped to the transmission lines but transmission tranches were excluded from the analysis.

  The negative reliability impacts resulting from PSPS and EPSS wildfire mitigation are also included. Net Benefits of PSPS and EPSS are then computed based on the Wildfire Risk reduction net of PSPS and EPSS consequences.

TABLE 1-16
PSPS AND EPSS DVC WILDFIRE BENEFITS (2027-2030)

			Wildfire Risk Reduction from PSPS and EPSS			PSPS and EPSS Consequence			Net Benefit of PSPS and EPSS		
			($M, risk adj.)		(%)	($M, risk adj.)		(%)[(a)]	($M, risk adj.)		(%)
Line No.	HFTD – Distribution Tranche Group	% DVC Cust.	*DVC*	*Non-DVC*	*DVC*	*DVC*	*Non-DVC*	*DVC*	*DVC*	*Non-DVC*	*DVC*
1	Tranche 1	23%	492	1,220	29%	85	281	23%	407	938	30%
2	Tranche 2	18%	418	1,194	26%	106	480	18%	312	714	30%
3	Tranche 3	35%	828	1,156	42%	204	377	35%	624	778	44%
4	Tranche 4	32%	1,416	2,210	39%	174	374	32%	1,242	1,836	40%
5	Tranche 5	28%	1,949	3,434	36%	132	340	28%	1,816	3,094	37%
6	Tranche 6	31%	1,866	3,497	35%	208	467	31%	1,658	3,029	35%
7	Tranche 7	20%	1,545	4,002	28%	133	521	20%	1,413	3,481	29%
8	Tranche 8	22%	1,735	3,913	31%	230	816	22%	1,505	3,097	33%
9	Tranche 9	15%	1,214	4,484	21%	245	1,443	15%	968	3,041	24%
10	Tranche 10	13%	967	3,918	20%	1,240	8,627	13%	(273)	(4,709)	5%
11	Overall Total	29%	12,431	29,028	30%	2,758	13,728	17%	9,673	15,300	39%

(a) While the allocation of PSPS and EPSS consequence was done proportionally to DVC customers in each tranche, because the risk per customer is different in each tranche, the total % DVC customers (29%) and the % DVC risk (17%) is not expected to be the same.

TABLE 1-17
PSPS AND EPSS ANNUALIZED DVC RELIABILITY IMPACTS

Line No.	Distribution Tranche Group	% DVC Customers	DVC EPSS Risk ($M, Risk-Adjusted)	DVC PSPS Risk($M, Risk-Adjusted)	Total DVC PSPS and EPSS Risk	% DVC Risk[(a)]
1	Tranche 1	23%	7	20	27	23%
2	Tranche 2	18%	9	25	34	18%
3	Tranche 3	35%	12	53	65	35%
4	Tranche 4	32%	8	47	56	32%
5	Tranche 5	28%	10	32	42	28%
6	Tranche 6	31%	15	51	66	31%
7	Tranche 7	20%	13	30	42	20%
8	Tranche 8	22%	15	58	73	22%
9	Tranche 9	15%	23	55	78	15%
10	Tranche 10	13%	143	252	395	13%
11	Overall Total	29%	255	623	878	17%

(a) While the allocation of PSPS and EPSS consequence was done proportionally to DVC customers in each tranche, because the risk per customer is different in each tranche, the total % DVC customers (29%) and the % DVC risk (17%) is not expected to be the same.

- System Hardening [UG]: PG&E's undergrounding program targets HFTD/HFRA locations, and only these tranches are presented in Table 1-18. The overall risk reduction per tranche was multiplied by the DVC percentage to estimate DVC Benefits over the four-year RAMP period. During the period of 2027-2030, work is being performed in the top five tranches, and the assumption is that PG&E will target the highest risk CPZs in earlier years.

TABLE 1-18
SYSTEM HARDENING [UG] DVC WF BENEFITS

Line No.	Distribution Tranche Group	% DVC Customers	Wildfire Risk Reduction From System Hardening (NPV $M, Risk Adj) DVC	Wildfire Risk Reduction From System Hardening (NPV $M, Risk Adj) Non-DVC	Wildfire Risk Reduction From System Hardening (%) DVC	2027-2030 Spend ($M) DVC	2027-2030 Spend ($M) Non-DVC	2027-2030 Spend (%) DVC
1	Tranche 1	23%	480	1,190	29%	72	240	23%
2	Tranche 2	18%	541	1,544	26%	86	391	18%
3	Tranche 3	35%	6,837	9,549	42%	736	1,362	35%
4	Tranche 4	32%	9,517	14,849	39%	1,013	2,172	32%
5	Tranche 5	28%	1,393	2,456	36%	127	327	28%
6	Grand Total	29%	18,768	29,588	39%	2,034	4,493	31%

4) Cost Comparison

Using the tranche percentage approach, PG&E expects $2 billion or 31 percent to be spent on System Hardening [UG] mitigation reducing risk in DVCs, relative to $6.5 billion forecasted mitigation budget for the 4-year RAMP period of 2027-2030.

C. 2023-2026 Control and Mitigation Plan

PG&E deploys a wide range of control and mitigation programs to reduce Wildfire Risk. These programs continue to build on its integrated strategy, focusing on monitoring/data collection, operational mitigations, and system resilience to reduce ignitions and impacts to our customers. Exhibit (PG&E-4), WP EO-WLDFR-15 list all the controls and mitigations PG&E included in its 2020 RAMP, 2023 GRC, and 2024 RAMP (2024-2026 and 2027-2030). The tables provide a view as to those controls and mitigations that are ongoing, those that are no longer in place, and new mitigations. In the sections following, PG&E describes the controls and mitigations in place during the 2023-2026 timeframe and highlights significant changes to these programs during the 2027-2030 periods.

PG&E presents its control and mitigation programs as both individual programs and as part of larger organizational initiatives to manage Wildfire Risk. Each of the sections below includes a description of the initiatives followed by individual program descriptions that include the associated initiative. Individual programs have an associated Program ID.

1. Controls

a. Vegetation Inspection and Control Programs

Vegetation inspection and control programs help PG&E address and manage the vegetation driver, which contributes the most risk to the wildfire baseline.

The 2024 RAMP also includes additional vegetation programs tied to our transmission system. This includes integrated VM, as well as routine and second patrols.

- WLDFR-C001 – VM Distribution Routine Patrols: The VM Distribution Routine Patrol Program performs scheduled inspections on OH primary and secondary distribution facilities to maintain radial clearance between vegetation and conductors. This is done by identifying trees that encroach the Minimum Distance Requirement (MDR) in accordance with regulatory requirements and/or PG&E procedures. In addition, dead, dying, and declining trees that may fail and strike conductors are also identified and mitigated. PG&E's VM distribution program inspects approximately 80,000 miles of OH distribution electric facilities on a recurring annual cycle. This program support compliance with GO-95 Rule 35.
- WLDFR-C002 – VM Distribution – Second Patrols: In accordance with regulatory requirements and/or PG&E's Distribution Inspection Procedure TD-7102P-01, the VM Distribution Second Patrol Program performs scheduled patrols on a six-month offset (approximately) from the routine patrol on OH primary and secondary distribution facilities. The primary target for secondary

patrols is HFTD/HFRA, but exceptions and additional areas are included to appropriately address vegetation associated risks.

The objective of the Second Patrol is to maintain radial clearance between vegetation and conductors by identifying trees that may encroach within the MDRs and by identifying dead, dying, and declining trees that may fail and strike conductors.

- WLDFR-C036: Routine Patrols Veg – Transmission: PG&E's Routine Patrols Veg - Transmission Program is designed to comply with state and federal laws and regulations: (1) FAC 003 (2) GO 95, Rule 35; (3) California PRC Section 4293. Through the Transmission annual inspection program, PG&E identifies vegetation-related issues and scenarios. These scenarios include: (a) Vegetation that has or may encroach the PG&E Minimum Clearance Distance based on the anticipated growth rate before the next annual work cycle, and (b) Vegetation (categorized as either a whole tree or portion of tree) that may impact PG&E electric facilities.
- WLDFR-C037: Second Patrols Veg – Transmission: The Second Patrols Veg – Transmission Program inspects OH electric transmission facilities (including idle) within HFTD/HFRA for vegetation that may impact PG&E electric facilities before the next annual work cycle. PG&E conducts a Second Patrol at the height of the vegetation growing season, which coincides with the beginning of the most active part of the California fire season, based on historical data. This program allows PG&E to conduct a supplemental assessment of potential tree growth, following seasonal rain to reduce the potential of ignitions.

b. Distribution Maintenance and Repair Programs

PG&E's distribution steady state maintenance and repair programs identify corrective actions from foundational inspection work governed by GO 165 and performed in accordance with the Electric Distribution Preventive Maintenance (EDPM) Manual. PG&E's methods of inspection include detailed ground inspections, ground patrols, aerial inspections, and when appropriate, infrared (IR) inspections.

- WLDFR-C009 – Overloaded Transformers Replacement: The Overloaded Transformers Replacement Program enables replacement of transformers identified through overload reports using SmartMeter™ data, through recorded high oil temperature indicators, or through multiple thermal protective device operations during peak load periods. This does not include replacement of transformers identified via New Business and Work at the Request of Others or any other processes. Replacement of overloaded transformers reduces likelihood of an ignition during normal operation by reducing the likelihood of failure of the transformer.
- WLDFR-C019 – Emergency Distribution Replacements [17B]: The Emergency Distribution Replacements Program repairs or replaces items identified as part of the inspections programs that are considered as safety hazards or at risk for potential immediate failure. This program addresses tags identified as the highest priority work. Crews are expected to make safe the asset/safety hazard or to address the maintenance tags in an accelerated timeline. This program supports compliance with General Order (GO) 95.
- WLDFR-C020 – Distribution Steady State Proactive Replacements [2AA]: The Distribution Steady State Proactive Replacements Program manages the replacement of deteriorated OH facilities that are not an imminent hazard and have not caused an outage. Facilities include crossarms, leaking transformers, and conductor. This program relates to safety, reliability, and maintenance because it addresses a non-conformance identified by preventative maintenance programs, such as inspections and patrols, as well as internal operational processes. This program supports compliance with GO 95.
- WLDFR-C021 – Distribution Steady State Maintenance Replacements [KAA]: The Distribution Steady State Maintenance Replacements Program addresses corrective actions from foundational inspection work governed by GO 165 and performed in accordance with the EDPM Manual. This program reduces the risk

associated to the Wildfire Risk, the Failure of Electric Distribution Overhead Assets risk, and supports meeting compliance requirements. This program supports compliance with GO 95.

- WLDFR-C022 – Distribution Steady State Maintenance Replacements [KAQ]: The Distribution Steady State Maintenance Replacements program addresses corrective actions tied to pole bridging and bonding from foundational inspection work governed by GO 165 and performed in accordance with the Electric Distribution Preventive Maintenance Manual. This program reduces the risk associated to the Wildfire Risk, the Failure of Electric Distribution Overhead Assets risk, and supports meeting compliance requirements. This program supports compliance with GO 95.

c. Distribution Pole Programs

Distribution poles are inspected and evaluated to determine their condition to support pole mounted equipment and to safely keep conductors OH. When deterioration is detected, the distribution poles are remediated through replacement or reinforcement, which reduces the risk of failure that may cause ignition.

- WLDFR-C014 – Pole Replacement: The Pole Replacement Program identifies poles for replacement when an existing pole is found to be degraded and/or deficient. Poles are identified for replacement through routine inspections, which include patrols, detailed visual inspections, and intrusive inspections. Pole replacement includes providing more robust and up-to-standard designs for poles. These designs might include larger, stronger poles or larger clearances. This program supports compliance with GO 95.
- WLDFR-C015 – Overloaded Pole Replacements: The Overloaded Pole Replacement Program identifies poles for replacement when an existing pole is found to be overloaded. This is done when assessing the pole loading through the pole loading assessment program, routine inspections or when the pole has other planned work (i.e., transformer replacement, etc.). Poles are also identified

for replacement when mechanically overloaded and a larger pole is required to support the conductor and OH equipment.

- WLDFR-C018 – Pole Restoration Program: The Pole Restoration Program provides life extension for existing poles by installing a steel truss at the base of the wood poles, strengthening it. Poles are tagged for reinforcement through routine intrusive inspections and may be reinforced if the degradation is at or below ground level. To qualify for reinforcement, the pole must be in good health above ground to support the banding of the steel truss to the wood pole.

d. Distribution Animal Abatement Programs

Animal abatement programs address the installation of new equipment, or retrofitting of existing equipment, with protection measures intended to reduce animal contacts. This includes avian protection on distribution poles, such as jumper covers, perch guards, or perching platforms. It also includes animal abatement work in substations.

PG&E has two categorized programs for animal abatement. 2AB and KAC are the reactive capital and expense programs, while 2AC and KAD are proactive capital and expense programs. Both programs primarily address bird-caused outages.

- WLDFR-C016 – Animal Abatement (Reactive) [2AB, KAC]: The reactive Animal Abatement Programs deploys animal mitigations to locations in response to animal-related outage or ignition to reduce the likelihood that the event will occur again. It includes capital modifications made to distribution poles, as well as expense repairs, replacements, or installations of bird guard materials. Bird guard materials include insulated jumpers, bushing covers, line covers, or perching platforms on incident and/or adjacent poles in response to bird incidents. This work is performed per U.S. Fish and Wildlife Service agreements and Utility Standard TD-2321S. Though this program is primarily deployed as a wildfire mitigation, it also provides additional risk reduction to the Failure of Electric Distribution Overhead Asset Failure risk by reducing animal-related outages.

- WLDFR-C017 – Animal Abatement (Proactive) [2AC, KAD]: The proactive Animal Abatement Program deploys animal mitigations to locations where there is believed to be a risk of animal contact or ignition. It includes capital modifications made to distribution poles, as well as expense repair, replacements, or installations of bird guard materials, such as insulated jumpers, bushing covers, line covers, or perching platforms, as part of the annual pole retrofit program. Though this program is primarily deployed as a wildfire mitigation, it also provides additional risk reduction to the Failure of Electric Distribution Overhead Asset Failure risk by reducing animal-related outages.

e. Transmission Maintenance and Repair Programs

Equipment conditions of transmission OH assets are assessed through our foundational programs of patrols, inspections, and high-definition images. These assessments determine if equipment poses a risk of failure or if they are no longer able to perform required functions. Maintenance, repair, and replacement tags can also be generated in post-event scenarios, depending on costs, whereas replacements would be required after assets are damaged by fires or car-strikes.

- WLDFR-C031 – Capital Transmission Steady State Pole Replacement: The Capital Transmission Steady State Maintenance Notification program provides mitigation to identified transmission asset issues, governed by CPUC GO 95 Rule 18. This includes pole replacement work. The replacement or installation of poles provides new, up-to-standard design equipment, which can lower Wildfire Risk when the asset resides within HFTD/HFRA. Specifically, it applies to drivers such as equipment/facility failure. It can help with all Wildfire Risk outcomes, ranging from small to catastrophic fires. Ignition-related HFTD/HFRA tags are prioritized based on GO 95, Rule 18 priority level.
- WLDFR-C032 – Capital Transmission Steady State Replacement: The Capital Transmission Steady State Maintenance Notification program provides mitigation to identified transmission asset issues,

governed by CPUC GO 95 Rule 18. This may include work such as replacing insulators, crossarms, and other equipment. The replacement or installation of assets such as insulators and crossarms provides new, up-to-standard designed equipment, which can lower Wildfire Risk when the asset resides within HFTD/HFRA. Specifically, it applies to drivers such as equipment/facility failure, wire-to-wire contact, vandalism/theft, and contamination. It can help with all Wildfire Risk outcomes, ranging from small to catastrophic fires. Ignition-related HFTD/HFRA tags are prioritized based on GO 95, Rule 18 priority level.

- <u>WLDFR-C033 – Emergency Transmission Capital Replacement</u>: The Emergency Transmission Capital Replacement Program targets work to replace damaged transmission line-related assets, as governed by CPUC GO 95 Rule 18 Level 1 designation. This damage may have resulted in an outage through in-service failure or may require immediate response due to safety. Capital programs fully replace capital assets, such as replacing a transformer.

  This program includes rebuilding transmission assets damaged by fires. Historically, emergency work variation by year is mostly influenced by wildfires and the need to rebuild assets after fires occur. Replacement asset work in an emergency can either prevent wildfires via just-in-time replacement or assist in restoration after a wildfire event via a post-fire rebuild. The program can help with all Wildfire Risk outcomes, ranging from small to catastrophic fires. Emergency work is considered critical and is prioritized accordingly.
- <u>WLDFR-C034 – Expense Transmission Steady State Replacement</u>: The Expense Transmission Steady State Replacement Program provides mitigation to identified transmission asset issues, as governed by CPUC GO 95 Rule 18. This may include work such as repairing or replacing hardware, as well as repairing conductors, foundations, structures, etc. The repair of transmission assets, or replacement of assets, such as hardware, provides life extension and hardening of the assets. This can lower Wildfire Risk when the asset resides within HFTD/HFRA, specifically as applied to drivers

such as equipment/facility failure, vandalism / theft, and contamination. The program can assist with all Wildfire Risk outcomes, ranging from small to catastrophic fires. Ignition-related HFTD tags are prioritized based on GO 95, Rule 18 priority level.

- WLDFR-C035 – Emergency Transmission Expense Replacement: The Emergency Transmission Expense Replacement Program aims to repair damaged transmission line-related assets, as governed by CPUC GO 95 Rule 18 Level 1 designation. This damage may have resulted in an outage through in-service failure or may require immediate response due to safety. Expense programs replace assets that are expense line items or that are repairs to capital assets, such as pole treatments or replacing a fuse in a fuse housing.

  Replacement asset work in an emergency can help prevent wildfires via just-in-time replacement or assist in restoration after a wildfire event via a post-fire rebuild. The program can help with Wildfire Risk outcomes, ranging from small to catastrophic fires. Emergency work is considered critical and is prioritized accordingly.

2. Mitigations

a. Distribution Grid Hardening Mitigations

System resilience programs are permanent wildfire mitigations. These programs change the construction or configuration of the grid by replacing utility assets with new more resilient equipment or by changing the configuration of assets on the system. These programs include component replacements, such as the Expulsion Fuse Program, which replaces assets with known Wildfire Risk with less risky components. It also includes more holistic programs, such as System Hardening and Undergrounding.

- WLDFR-M002 – System Hardening [OH]: PG&E's System Hardening [OH] Program hardens current circuits through the replacement of bare OH primary conductor and other existing OH distribution assets with equipment that increases system resiliency. This program is primarily targeted to address Wildfire Risk but also provides significant risk reduction for the Failure of Electric Distribution Overhead Assets risk. Activities in the System Hardening [OH] program include:

- Covered Conductor: This activity replaces bare OH primary conductor and associated framing with conductor that is insulated with abrasion-resistant polyethylene coating;
- Pole Replacement: Existing poles are evaluated for the strength requirements to withstand the new, heavier covered conductor and associated equipment. If the pole does not meet the new requirements, PG&E will replace it using wood, intumescent-wrapped wood, or composite poles;
- Replacement of Non-Exempt Equipment: This activity focuses upon replacement of existing primary line equipment, such as fuses, cutouts, and switches, with equipment that has been certified by CAL FIRE as low fire risk;
- Replacement of OH Distribution Line Transformers: This considers the upgrading of transformers to those that contain "FR3" dielectric fluid, as part of PG&E's current equipment standards;
- Framing and Animal Protection Upgrades: This activity looks at replacing crossarms with composite arms, wrapping jumpers, and installing animal protection upgrades; and
- Vegetation Clearing to Enable Work: This activity manages clearing of vegetation on the ground directly beneath lines to execute hardening work. It also addresses vegetation clearing to meet regulatory requirements if there is a change to a line's profile (e.g., taller pole or wider crossarms) because of a hardening project.

- WLDFR-M003: Non-Exempt Surge Arrester Replacement: The Non-Exempt Surge Arrester Replacement Program replaces existing non-exempt surge arresters with exempt surge arresters at locations with potentially deficient grounding. The exempt surge arresters have less propensity to cause a fire ignition. In addition, PG&E addresses common grounding by separating out the grounding on poles where surge arresters and transformers are co-located and shared a single ground.

Surge protection is an initial defense against the instant or gradual destruction of electrical equipment. By upgrading the equipment, continuing to separate the grounds, and conducting ground and impedance improvements, lightning strikes and other surges can safely dissipate to their dedicated surge arrester ground while not affecting the separately grounded transformer (co-located on the same pole). The non-exempt surge arresters are replaced with new surge arresters which are considered CAL FIRE certified exempt equipment, which reduces the likelihood of an ignition during normal operation. This program addresses the replacement of the remaining non-exempt surge arresters in HFTD/HFRA locations and was completed in 2023.

- <u>WLDFR-M004 – Expulsion Fuse Replacement</u>: The Expulsion Fuse Replacement Program reduces the consequence of potential ignitions by replacement and/or removal of non-exempt fuses. In general, the risk of ignition associated to a fuse on a line is reduced through the complete removal and/or replacement of non-exempt equipment with exempt equipment. Fuses are intended to protect the main line of the distribution feeder from faults occurring on the laterals. The replacement of non-exempt equipment with exempt equipment reduces ignition risk because the exempt equipment does not generate arcs and/or sparks during normal operation.
- <u>WLDFR-M010 – Additional System Automation and Protection – FuseSaver</u>: The Additional System Automation and Protection – FuseSaver Program installs electrical OH equipment designed to isolate faulted lines, limit the scope of electrical outages, and improve electric service reliability. This program was primarily implemented to address Wildfire Risk associated with wire down events, where a downed wire remains energized by a back feed condition. The installations target the HFTD/HFRA areas, as well as protect equipment within the HFTD/HFRA.

- WLDFR-M011 – System Hardening [Remote Grid]: Remote grids provide utility service using standalone power systems (SPS) and utility infrastructure for continuous, permanent energy delivery to remote locations. Resolution (Res.) E-5132[6] approved PG&E's Remote Grid SPS Supplemental Provisions Agreement and limited its use in aggregate to two megawatts of historical measured peak customer load. Res.E-5242[7] allows PG&E to offer remote grids as a sole standard service offering under certain conditions, within the Remote Grid Pilot.

  The primary use case for remote grids is to reduce wildfire ignition risk by eliminating OH distribution lines that serve a small number of customers at the outskirts of the distribution system. The elimination of these distribution lines aims to: (1) reduce the likelihood of fire ignition due to damage or failure of such lines; and/or (2) eliminate or reduce the cost to harden the lines and/or perform line maintenance and VM. In addition, remote grids can be a rebuild solution where a wildfire has damaged electric distribution infrastructure in remote areas. PG&E has identified distinct segments of its distribution system where remote grid service may be preferable to conventional service alternatives, such as undergrounding. As of early 2024, there are approximately 20 remote grid systems in varying stages of project development and approximately ten systems in an implementation stage. There are six operational remote grid systems as of early 2024.

- WLDFR-M014 – Butte County Rebuild: The Butte County Rebuild Program is focused on rebuilding the utility infrastructure to serve the city of Paradise and the surrounding County assets that were destroyed during the Camp Fire. In the 2018 Camp Fire, over 18,000 structures were destroyed, including 13,400 premises. The impacted area is in Tier 2 (Elevated) and Tier 3 (Extreme) fire risk areas, with a very small area in Tier 1 (Normal). Approximately

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6 Res.E-5132 (Mar. 18, 2021).

7 Res.E-5242 (Jan. 12, 2023).

207 miles of electric lines were destroyed, with some having been burned multiple times in the previous decade.

The Town of Paradise and Butte County expressed strong desire for UG electric infrastructure. In 2019, PG&E committed to rebuilding the infrastructure affected by the fire, including undergrounding existing facilities.

- WLDFR-M022 – System Hardening [UG]: PG&E's System Hardening Undergrounding Program converts OH distribution lines and equipment to UG to permanently reduce wildfire ignition risk. The System Hardening Undergrounding Program falls within the OEIS definition of Undergrounding of Electric Lines and/or Equipment: *Actions taken to convert OH electric lines and/or equipment to UG electric lines and/or equipment (i.e., located UG and in accordance with GO 128)*. When circuit segments are targeted for system hardening, some factors that may lead to undergrounding being the preferred mitigation are tree strike potential, proximity to a major ingress or egress route, localized fuel types, and past fire history.

  In July 2021, PG&E announced a multi-year program to UG 10,000 distribution circuit miles in and near HFTDs to address California's growing Wildfire Risk; the System Hardening undergrounding program is a key component of that effort.

  PG&E is filing its 10 year undergrounding plan as part of the Senate Bill (SB) 884 legislation. This filing will occur in the 2024 2026 timeframe. The results of this filing will impact the pace of execution for undergrounding significantly. PG&E anticipates completing additional undergrounding miles based on the results of the SB 884 filing and will increase the amount of risk reduction related to this program.

b. Operational Mitigations

Operational mitigations are activities that PG&E actively performs to provide ongoing risk reduction. These include changing system configuration, such as modifying reclosing settings, or implementing programs like PSPS and EPSS. Operational mitigations are activities that can be deployed quickly and influence how we manage the electric grid. These programs require dynamic action on the part of the utility to move the system away from the standard operating state during periods of elevated Wildfire Risk and moving the system back into standard operating state when the elevated Wildfire Risk has passed.

- <u>WLDFR-M008 – Safety Infrastructure Protection Teams (SIPT)</u>: The SIPT supports resources performing work in high fire hazard areas. SIPT crews consist of two to three International Brotherhood of Electrical-Workers (IBEW) represented employees who are trained and certified as SIPT personnel. The crews provide a variety of services including standby resources for PG&E crews performing work in high fire hazard areas, pre-treatment of PG&E assets during any ongoing fire, fire protection to PG&E assets, and emergency medical services. SIPT crews perform high priority fire mitigation work, protect PG&E assets, and gather critical data to help prepare for and manage Wildfire Risk.
- <u>WLDFR-M020 – EPSS</u>: EPSS is a protective technology that allows line protection devices, such as line reclosers, to address faults of varying magnitude and rapidly de-energize the line. These faults may occur due to vegetation striking a line, animal interference, third-party interference (e.g., a vehicle hitting a line), or equipment failure. EPSS also includes Downed Conductor Detection (DCD) which uses sophisticated harmonic analysis to detect arcing present during high impedance faults (down to approximately one Amp) and to provide an immediate trip response. The DCD program provides enhanced ground fault protection to address low current, high impedance faults.

  EPSS settings also help protect customers and communities from potential ignitions that could result in wildfires by de-energizing the line when a fault is detected on the powerline. With its fast fault detection enabling the ability to quickly and automatically shut-off power within one tenth of a second, EPSS significantly contributes to mitigating potential fires.

In response to dynamic climate change, PG&E established the EPSS pilot program in July 2021 to help prevent wildfires. The program enabled modified settings on some PG&E equipment to automatically turn off the power more quickly if the system detected a hazard. Circuits enabled with EPSS are configured to clear high-current bolted fault conditions at 100 milliseconds or less. EPSS settings also allow circuit breakers and reclosers to clear faults beyond fuses. This allows clearance of all fuse-protected circuit segments with ganged three-phase interruption to prevent backfeed into the fault.

In 2022, PG&E expanded and optimized EPSS capabilities across HFTD/HFRA areas based on reliability impact and Wildfire Risk. This was done across 170 circuits in 2021 to approximately 1,000 circuits in 2022. Additionally, PG&E refined its protocol for EPSS activation and deactivation based on real-time risk at the circuit level. This refinement helped minimize customer reliability impacts by reducing outage frequency and duration from EPSS enablement. PG&E also increased its EPSS Program outreach and engagement with customers, communities, and regulators. This improved communication relative to the EPSS Program and related-activities, while also enabling coordinated efforts with other Safety, Wildfire, and Reliability programs. Lastly, the scope for EPSS expanded in 2022-2023 to all powerlines in high fire-risk areas and select adjacent EPSS buffer areas. Expansion drove improvements, and these settings helped to prevent wildfires, even with higher risk conditions.

- <u>WLDFR-M001 – PSPS:</u>[8] PG&E's PSPS Program evaluates whether to proactively de-energize a portion of our electric system to prevent an ignition during extreme fire weather patterns; this is done as a public safety measure of last resort. De-energization may be necessary when a combination of winds and location-specific

[8] For the risk modeling purpose, M021 includes the benefits of PSPS and EPSS together to estimate the incremental impact of PSPS. For the purpose of describing the mitigation, only PSPS is described here.

factors, such as vegetation dryness, are forecast to present a statistically high likelihood of damage or disruption to above-ground power lines, indicating a heightened risk of catastrophic wildfire. PSPS is used as a measure of last resort and is only deployed when other measures are not adequate alternatives. Before lines de-energized during PSPS can be re-energized, PG&E patrols the segments of lines that experienced the elevated fire danger conditions to ensure that they can be safely returned to service. The cost of these patrols is considered part of the cost of the PSPS mitigation. This mitigation has the potential to reduce the Equipment Failure and Vegetation drivers.

To inform the geographic scope of PSPS events, PG&E performs a fire threat assessment of its service territory. This assessment focuses on identifying areas in PG&E service territory where existing or future OH electrical infrastructure could be the source of an ignition that results in a catastrophic fire during a hazardous offshore wind event. These areas are collectively referred to as PG&E's HFRA. All OH electric distribution and transmission infrastructure within the HFRA is potentially subject to PSPS. In scoping for a PSPS event, the HFRA serves as an initial geospatial filter; event-specific geospatial data concerning weather, fuel conditions, and assets are then overlaid and analyzed to arrive at a final PSPS scope. During the 2019 fire season, extreme hazard weather conditions were particularly severe, resulting in PG&E conducting nine PSPS events. These events ranged in impact from approximately ten thousand to approximately one million customers. Due to more favorable weather in 2022, PG&E activated the EOC once for a potential PSPS event; however, PG&E did not need to de-energize lines during the canceled PSPS event. In 2023, PG&E had two PSPS events.

c. Distribution Backlog

The intent of PG&E's open tag backlog reduction program is to eliminate PG&E's existing HFTD/HFRA Electric Corrective (EC) notifications distribution backlog by 2029 to be in compliance with

GO 95 Rule 18, barring external factors. For RAMP calculations, the backlog consists of any open tag not completed through 2023.

PG&E's enhanced inspection program called Wildfire Safety Inspection Program (WSIP) was initiated in 2019 to specifically identify situations that posed Wildfire Risk from degraded infrastructure. This created an influx of EC notifications. The notifications with immediate urgency were completed while the remainder are continued to be worked in a risk-informed manner. The Distribution Backlog program is addressing these findings. Maintenance tags generated through our inspection programs are assigned a priority based on the potential safety impact.

- <u>WLDFR-M023 – Open Tag Reduction – Distribution (Pole Backlog)</u>: The Open Tag Reduction – Distribution Program reduces the backlog of open notifications related to distribution poles identified as deteriorated / damaged and in need of replacement. This program enables Wildfire Risk reduction by reducing potential ignition risk.
- <u>WLDFR-M024 – Backlog Open Tag Reduction – Distribution (Capital – 2AA)</u>: The Backlog Open Tag Reduction – Distribution (Capital – 2AA) Program reduces the backlog of open notifications related to deteriorated distribution OH facilities that are not an imminent hazard and have not caused an outage. Facilities include crossarms, non-emergency, leaking transformers, conductor, capacitors, lightning arrestors, switches, removal of capital electric idle facilities (including poles), street light heads, and equipment.
- <u>WLDFR-M025 – Backlog Open Tag Reduction - Distribution (Expense – KAA)</u>: The Backlog Open Tag Reduction – Distribution (Expense – KAA) Program reduces the backlog of open notifications that require repair of OH distribution facilities or replacement of individual components that are not an imminent hazard and have not caused an outage. Facilities include connectors, insulators, low conductors, leaning poles, slack guys, etc. The program repairs, replaces, or installs grounds, moldings, leaking bushings, and

related work on all OH transformers and equipment associated with transformers.

- WLDFR-M026 – Pole Programs - Replace Tree Attachments: The Pole Programs – Replace Tree Attachments program identifies dead or dying trees with tree attachments for mitigation through routine inspections, which include patrols and detailed visual inspections, or when assessing the area for planned work (i.e., reconductoring, service drops, etc.). PG&E's current standard does not allow for the use of tree attachments for any new installations. Historically, PG&E has used living trees as distribution poles in some areas, depending on surrounding conditions. These trees are inspected and evaluated to determine their condition to support pole mounted equipment and safely keep energized overhead conductors. When trees are identified as dead or dying, they are remediated by installing a new distribution pole and transferring the equipment and energized conductors from the tree to the new distribution pole, which reduces the risk of ignition.

d. Vegetation Mitigation Programs

VM maintains utility right of ways and clearances to reduce the likelihood and frequency of vegetation-related incidents. These programs focus on addressing branches and vegetation that may contact lines, dead or dying trees that may contact lines, trees that have been identified as hazards, and clearing potential fuels from surrounding assets.

In 2022, PG&E sunset the Enhanced Vegetation Management (EVM) Program and replaced it with the Focused Tree Inspections (FTI) and Vegetation Management (VM) for Operational Improvements program. Additionally, the Tree Removal Inventory (TRI) program was created to address the backlog of trees that were to be removed as part of the legacy EVM Program.

- WLDFR-M027 – Pole Clearing: This Pole Clearing Program addresses poles beyond the requirements of PRC Section 4292 in Local Responsibility areas inside HFTD and HFRA (e.g., pole clearing performed outside of the SRA). This is done on subject poles to reduce risks during fire seasons of variable extremes and/or durations. The VC Program works to complete annual initial clearing of all subject poles in advance of fire season.

- WLDFR-M028 – VM Distribution – FTI: The FTI Program targets PG&E's distribution system to identify and to mitigate areas that are likely to see higher rates of tree failures prior to the upcoming wildfire and winter storm seasons. It utilizes Tree Risk Assessment Qualification (TRAQ)-certified vegetation management inspectors (VMI) to ensure a higher qualification level of inspectors and is the best, most thorough, and consistent available. The goal of the program is to preempt tree failures, reducing vegetation-caused outages and vegetation-caused ignitions. This is a new transitional program for 2023 stemming from the conclusion of the EVM Program.

  The FTI program was piloted in 2023, targeting more than 250 OH electric line miles in four counties to capture known regional variation in forest canopy types. Lessons learned, WMP Revision Notices, and Areas of Continuous Improvement commitments in 2023 defined specific commitments for 2024-2025.

- WLDFR-M029 – VM Distribution – VM for Operational Mitigations (VMOM): VMOM began in 2022 under the management of the EPSS Project Management Organization (PMO). This program is intended to reduce customer impacts for more frequent vegetation outages that occur due to more sensitive EPSS-enabled circuit protection devices. There are two components to the VMOM program: (1) a Reactive approach, and (2) a Proactive approach. The VMOM program addresses the reliability impacts of EPSS and provides ancillary benefits to Wildfire Risk reduction by reducing the frequency of vegetation related events.

- WLDFR-M030 – VM – Tree Removal Inventory (TRI): TRI is a program that is intended to systematically work down trees that were previously identified through the EVM inspections. This program addresses risk by mitigating trees that have been previously identified as posing potential risk of striking energized OH conductors. Outstanding EVM-identified trees were mapped to the corresponding WRDM V3 Risk Model CPZs, which were then prioritized according to the company's WRDM V3 (Trunk Failure) risk ranking.

- WLDFR-M035 – Integrated Veg Management – Transmission: The Transmission Integrated Vegetation Management (TIVM) Program is an ongoing effort to maintain electric transmission-managed areas along transmission rights-of way (ROW) that have previously been cleared. It maintains vegetation control in wire zone and border zone areas underneath and adjacent to PG&E electric transmission facilities (managed areas). The anticipated outcomes of TIVM are to reduce vegetation-related outages and consequence of ignitions systemwide. It is also done to meet commitment-based obligations (e.g., CAISO Maintenance Practice, WMP).
- WLDFR-M037 – Substation Distribution - Defensible Spaces: The Substation Distribution Defensible Spaces Program includes the removal (where permitted) of dead, dying, or diseased vegetation, based on results and findings from substation defensible space inspections. Remaining vegetation is mowed, pruned, and trimmed to reduce ladder or flash fuels. Issues identified during utility defensible space inspections become work orders for Electric Operations (EO) and are executed to mitigate any defensible space issues that could pose a vegetation-related ignition risk.
- WLDFR-M039 – Substation Transmission – Defensible Spaces: The Substation Transmission Defensible Spaces Program focuses on the removal (where permitted) of dead, dying, or diseased vegetation, based on results and findings from substation defensible space inspections. Any remaining vegetation is mowed, pruned, and trimmed to reduce ladder or flash fuels. Issues identified during utility defensible space inspections become work orders for EO and are executed to mitigate any defensible space issues that could pose a vegetation-related ignition risk.

e. Transmission Grid Hardening Mitigations

Transmission Grid Hardening activities are changes to transmission system assets to increase the resilience of the transmission system. They consist of asset health-related programs to manage the condition of transmission assets and proactive programs that address assets or conditions that are a known Wildfire Risk.

- <u>WLDFR-M032 – Traditional OH Hardening – Line Removal</u>: PG&E follows the procedures and requirements in Management of Idle Electric Transmission Line Facilities Procedure (TD-1003P) to investigate potential idle facilities. When these facilities are identified and confirmed to be within an HFTD/HFRA and no longer having an operational need, they are prioritized for de-energization, grounding, and/or removal. Grounding of a de-energized line addresses residual Wildfire Risk of induction from nearby energized line(s) until conductor removal or repurposing of the facilities can occur.

  Transmission lines may also be considered for temporary or seasonal de-energization, depending on the operational needs and Wildfire Risk associated with the line. Transmission lines may be removed as part of the idle facility process or through other work such as line re-routing or re-building. As referenced in the 2023-2025 WMP, PG&E has enacted a 10-year plan to remove permanently abandoned transmission lines.
- <u>WLDFR-M033 – Traditional OH Hardening – Shunt Splices</u>: The Traditional OH Hardening – Shunt Splices Program focuses on the installation of shunt splices on top of existing splices. A conductor splice is a point of failure within a conductor span, due to factors such as corrosion, moisture intrusion, vibration, and workmanship variability. Certain types of splices, such as a twist splice, can have higher risk of failure as compared to other splice types. This installation eliminates the splice as a single point of failure, as a failure of the original splice would not result in down conductor. Lines prioritized for this program are based on higher risk splices and wildfire consequence.

- <u>WLDFR-M034 – HFTD/HFRA Open Tag Reduction – Transmission</u>: This program prioritizes open transmission work orders (notifications) based on priority levels as defined in the Electric Transmission Line Guidance for Setting Priority Codes Procedure (TD-8123-103). Ignition-related notifications in the HFTD and HFRA have a higher priority than non-HFTD, non-HFRA, and non-ignition-related notifications.
- <u>WLDFR-M036 – Traditional OH Hardening – System Hardening Transmission</u>: PG&E does not have a separate program for transmission OH system component hardening that specifically aligns with the updated OEIS' definition of traditional OH hardening. There are two levels of projects for transmission conductor hardening, with larger projects in the Targeted Line Rebuilt program and smaller projects in the Dispersed Conductor Component (Splice) Hardening and Conductor Segment Replacements. These programs focus on the risk associated with transmission line conductor failure, which may lead to wildfire ignition.

f. PSPS Mitigation Programs:

- <u>WPSPS-M001 – System Hardening [UG]</u>: PG&E's System Hardening Undergrounding Program converts OH distribution lines and equipment to UG to permanently reduce wildfire ignition risk. The System Hardening Undergrounding program falls within the OEIS definition of Undergrounding of Electric Lines and/or Equipment: *Actions taken to convert OH electric lines and/or equipment to UG electric lines and/or equipment (i.e., located UG and in accordance with GO 128)*. When circuit segments are targeted for system hardening, some factors that may lead to undergrounding being the preferred mitigation are tree strike potential, proximity to a major ingress or egress route, or localized fuel types and past fire history. By undergrounding electric facilities, previously exposed overhead facilities in heightened fire and wind conditions would no longer be exposed, resulting in no need for PSPS itself. In July 2021, PG&E announced a multi-year program to UG 10,000 distribution circuit miles in and near HFTDs to address

California's growing Wildfire Risk; the System Hardening undergrounding program is a key component of that effort.

- WPSPS-M002 – PSPS MSO Sectionalizer: The PSPS MSO Sectionalizer Program allows PG&E to further sectionalize the electrical system in locations where PSPS events may occur. This additional sectionalizing allows for more targeted PSPS events, resulting in few outages. Additionally, these sectionalizers allow for remote disconnect of faulted sections. The program allows PG&E to proactively manage power outages during extreme weather conditions, reducing the risk of wildfires and ensuring public safety.
- WPSPS-M003 – Portable Battery: The Portable Battery Program (PBP) provides portable backup battery solutions to Medical Baseline Customers (MBL) and Self-Identified Vulnerable (SIV) customers at risk of PSPS events to support resiliency during PSPS. The program provides a range of batteries from smaller (500 Wh) lightweight batteries to larger (6,000 Wh) batteries to meet the power needs of various medical devices. Larger batteries are delivered to those with higher energy needs. The PBP focuses on understanding customers' needs through conversation, discussing emergency plan preparedness, and assessing the best resiliency solution for each customer during PSPS.
- WPSPS-M004 – Permanent Battery: The Permanent Battery Program is a program that offers rebates to customers purchasing and interconnecting a permanent battery. The program is available to ~108,000 customers that are highly impacted by EPSS, regardless of medical baseline or income status.
- WPSPS-M005 – RSI Battery: The Residential Storage Initiative (RSI) Battery Program provides batteries and installation for select customers highly impacted by EPSS. The program focuses on providing support to vulnerable, low-income customers during wildfire safety outages, as well as medical baseline and California Alternate Rates for Energy (CARE) customers. As of December 2023, PG&E has provided permanent battery systems at no cost to 469 residential customers who had been frequently impacted by

outages because of PG&E's EPSS Program. Eligible customers were enrolled in the CARE program or the Medical Baseline program. Customers enrolled did not already have a customer resiliency solution (such as a battery or permanently installed generator) and had experienced the most frequent safety-related outages. The program is targeted at customers that are highly impacted by EPSS but provides ancillary PSPS benefits.

- <u>WPSPS-M006 – Temporary Generation</u>: Temporary Generation supports the mitigation of power loss and other customer impacts related to disruptions caused by PG&E's Public Safety Power Shutoff events. PG&E's Temporary Generation program include generators as well as the associated ancillary equipment and support services needed to transport, interconnect and/ or install, fuel, operate, and maintain generators. Temporary generation can be deployed for multiple workstreams that are intended to mitigate customer impacts of PSPS and EPSS events, which includes supporting substation microgrids, distribution microgrids, back-up power support (BUP), community resource centers.

g. EPSS Mitigation Programs

- <u>WEPSS-M009 – VM Distribution – VM for Operational Mitigations (VMOM)</u>: VMOM began in 2022 under the management of the EPSS Project Management Organization (PMO). This program is intended to reduce customer impacts for more frequent vegetation outages that occur due to more sensitive EPSS-enabled circuit protection devices. There are two components to the VMOM program: (1) a Reactive approach, and (2) a Proactive approach. This program is intended to primarily address the risk of vegetation related outages on EPSS enabled circuits, to reduce the impact of the extended duration of EPSS outages.
- <u>WEPSS-M011 – Portable Battery</u>: The Portable Battery Program (PBP) provides portable backup battery solutions to Medical Baseline Customers (MBL) and Self-Identified Vulnerable (SIV) customers at risk of PSPS events to support resiliency during EPSS outages. The program provides a range of batteries from smaller

(500 Wh) lightweight batteries to larger (6,000 Wh) batteries to meet the power needs of various medical devices. Larger batteries are delivered to those with higher energy needs. The program is intended to address PSPS risk but provides ancillary EPSS benefits.

- WEPSS-M012 – Permanent Battery: The Permanent Battery Program is a program that offers rebates to customers purchasing and interconnecting a permanent battery. The program is available to ~108,000 customers that are highly impacted by EPSS, regardless of medical baseline or income status.
- WEPSS-M013 – RSI Battery: The Residential Storage Initiative (RSI) Battery Program provides batteries and installation for select customers highly impacted by EPSS. The program focuses on providing support to vulnerable, low-income customers during wildfire safety outages, as well as medical baseline and CARE customers. As of December 2023, PG&E has provided permanent battery systems at no cost to 469 residential customers who had been frequently impacted by outages because of PG&E’s EPSS Program. Eligible customers were enrolled in the California Alternate Rates for Energy (CARE) program or the Medical Baseline program. Customers enrolled did not already have a customer resiliency solution (such as a battery or permanently installed generator) and had experienced the most frequent safety-related outages.

TABLE 1-19
PLANNED MITIGATIONS 2024-2026

Line No.	Mitigation ID[(a)]	Mitigation Name	Planned Units of Work: Units of Measurement[(b)]	2024	2025	2026	Total
1	DOVHD-M002, PCEEE-M002, WLDFR-M002	System Hardening [Overhead]	Miles	60	200	348	608
2	DOVHD-M004, WLDFR-M004	Expulsion Fuse Replacement	Fuses	3,000	1,829	–	4,829
3	WLDFR-M008	Safety Infrastructure Protection Teams	Poles	2,720	2,720	2,720	8,160
4	DOVHD-M010, WLDFR-M010	Additional System Automation and Protection – FuseSaver	Work Unit	71	–	–	71
5	WLDFR-M011	System Hardening [Remote Grid]	Miles	10	10	10	30
6	DOVHD-M014, WLDFR-M014	Butte County Rebuild	UG Miles	40	20	10	70
7	DOVHD-M022, PCEEE-M003, WLDFR-M022	System Hardening [Underground]	UG Miles	210	310	430	950
8	DOVHD-M023, WLDFR-M023	Backlog Open Tag Reduction – Distribution (Pole Backlog)	Pole Notifications	8,473	30,436	22,121	61,030
9	DOVHD-M024, WLDFR-M024	Backlog Open Tag Reduction – Distribution (Capital) [2AA]	Capital Non-Pole Notifications	7,869	3,178	1,461	12,508
10	DOVHD-M025, WLDFR-M025	Backlog Open Tag Reduction – Distribution (Expense) [KAA]	Expense Non-Pole Notifications	43,857	40,355	41,851	126,063
11	DOVHD-M026, WLDFR-M026	Pole Programs – Replace Tree Attachments	Poles	1,130	1,356	1,399	3,884
12	DOVHD-M027, WLDFR-M027	Pole Clearing	Poles	70,000	60,000	65,000	195,000
13	DOVHD-M028, WLDFR-M028	VM Distribution – Focused Tree Inspections[(c)]	Miles	1,807	1,788	1,788	5,383

TABLE 1-19
PLANNED MITIGATIONS 2024-2026
(CONTINUED)

			Planned Units of Work				
Line No.	Mitigation ID[a]	Mitigation Name	Units of Measurement[b]	2024	2025	2026	Total
14	DOVHD-M029, WLDFR-M029	VM Distribution – Operational Improvements	Trees	16,646	16,646	16,646	49,938
15	DOVHD-M030, WLDFR-M030	Vegetation Management – Tree Removal	Trees	20,000	25,000	44,488	89,488
16	WLDFR-M035	Integrated Vegetation Management – Transmission	Acres	6,504	6,504	6,504	19,512
17	WLDFR-M036	Traditional Overhead Hardening – System Hardening Transmission	Miles	–	5	–	5
18	WLDFR-M037	Substation Distribution – Defensible Spaces	Number of Substations	189	189	189	567
19	WLDFR-M039	Substation Transmission – Defensible Spaces	Number of Substations	82	82	82	246
20	WPSPS-M002	PSPS MSO Sectionalizer	# of Devices	8	–	–	8
21	DOVHD-M031, WEPSS-M011, WPSPS-M003	Portable Battery	# Batteries	4,050	3,645	3,281	10,976
22	DOVHD-M032, WEPSS-M012, WPSPS-M004	Permanent Battery	# Batteries	1,000	1,000	1,000	3,000
23	DOVHD-M033, WEPSS-M013, WPSPS-M005	RSI Battery	# Batteries	1,800	1,300	1,300	4,400

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

(b) The units of work are presented as used in the RAMP model because the model requires that units of work are standardized. These may differ in some instances from “rate case” units – the units referred to in PG&E’s General Rate Case or other proceedings.

(c) Based on the approved PG&E 2023-2025 WMP, VM Distribution - Focused Tree Inspections has transitioned to 1,500 miles/year.

Note: For additional details see WP EO-WLDFR-F.

Cost estimates for the work planned from 2024-2026 are shown in Tables 1-20 and 1-21 below.

TABLE 1-20
MITIGATION COST ESTIMATES
2024-2026 EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Mitigation ID[(a)]	Mitigation Name	2024	2025	2026	Total
1	WLDFR-M008	Safety Infrastructure Protection Teams	$22,940	$22,481	$19,109	$64,530
2	WLDFR-M020	EPSS	89,814	88,018	74,815	252,647
3	WLDFR-M001	PSPS	57,629	56,476	48,005	162,110
4	DOVHD-M025, WLDFR-M025	Backlog Open Tag Reduction – Distribution (Expense) [KAA]	103,684	105,174	104,977	313,835
5	DOVHD-M027, WLDFR-M027	Pole Clearing	28,803	27,363	25,995	82,161
6	DOVHD-M028, WLDFR-M028	VM Distribution – Focused Tree Inspections	220,069	220,291	220,629	660,989
7	DOVHD-M029, WLDFR-M029	VM Distribution – Operational Improvements	20,910	20,910	20,910	62,730
8	DOVHD-M030, WLDFR-M030	Vegetation Management – Tree Removal	44,090	55,113	98,075	197,278
9	WLDFR-M035	Integrated Vegetation Management – Transmission	13,385	13,385	13,385	40,154
10	WLDFR-M037	Substation Distribution – Defensible Spaces	2,500	2,450	2,082	7,032
11	WLDFR-M039	Substation Transmission – Defensible Spaces	1,282	1,257	1,068	3,608
12	DOVHD-M031, WEPSS-M011, WPSPS-M003	Portable Battery	12,590	11,331	10,199	34,120
13	DOVHD-M032, WEPSS-M012, WPSPS-M004	Permanent Battery	5,300	5,300	5,300	15,900

TABLE 1-20
MITIGATION COST ESTIMATES
2024-2026 EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)
(CONTINUED)

Line No.	Mitigation ID[a]	Mitigation Name	2024	2025	2026	Total
14	DOVHD-M033, WEPSS-M013, WPSPS-M005	RSI Battery	32,134	23,208	23,208	78,550
15	WPSPS-M006	Temporary Generation	12,701	12,447	10,580	35,729
16		Total	$667,831	$665,204	$678,337	$2,011,373

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

For additional details see WP EO-WLDFR-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3. For System Hardening, Maintenance Tags and IGP-related programs, the cost estimates are based on the anticipated work forecasted over the forecast years which deviates from the 2024 budget.

TABLE 1-21
MITIGATION COST ESTIMATES
2024-2026 CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Mitigation ID[(a)]	Mitigation Name	2024	2025	2026	Total
1	DOVHD-M002, PCEEE-M002, WLDFR-M002	System Hardening [Overhead]	$88,585	$229,063	$368,800	$686,447
2	DOVHD-M004, WLDFR-M004	Expulsion Fuse Replacement	19,800	12,313	–	32,113
3	WLDFR-M008	Safety Infrastructure Protection Teams	785	801	681	2,267
4	DOVHD-M010, WLDFR-M010	Additional System Automation and Protection – FuseSaver	7,865	–	–	7,865
5	WLDFR-M011	System Hardening [Remote Grid]	12,900	12,900	12,900	38,700
6	DOVHD-M014, WLDFR-M014	Butte County Rebuild	155,121	66,275	31,497	252,893
7	WLDFR-M020	EPSS	68,963	80,349	54,350	203,662
8	WLDFR-M001	PSPS	2,042	2,083	1,770	5,895
9	DOVHD-M022, PCEEE-M003, WLDFR-M022	System Hardening [Underground]	832,192	1,167,576	1,395,652	3,395,420
10	DOVHD-M023, WLDFR-M023	Backlog Open Tag Reduction – Distribution (Pole Backlog)	212,575	652,203	471,726	1,336,504
11	DOVHD-M024, WLDFR-M024	Backlog Open Tag Reduction – Distribution (Capital) [2AA]	100,145	40,149	18,458	158,752
12	DOVHD-M026, WLDFR-M026	Pole Programs – Replace Tree Attachments	30,158	30,761	26,147	87,065
13	WLDFR-M036	Traditional overhead hardening – System Hardening Transmission	–	16,739	–	16,739
14	WPSPS-M002	PSPS MSO Sectionalizer	292	–	–	292
15		Total	$1,531,423	$2,311,211	$2,381,980	$6,224,615

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

Note: For additional details see WP EO-WLDFR-F.
The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3. For System Hardening, Maintenance Tags and IGP-related programs, the cost estimates are based on the anticipated work forecasted over the forecast years which deviates from the 2024 budget.

3. Foundational Activities

As discussed in Exhibit (PG&E 2), Chapter 2, foundational activities are programs that enable two or more control or mitigation programs but do not directly reduce the consequences or the likelihood of risk events. Table 1-22 lists foundational activities that meet this definition and includes: (1) information on the control or mitigation programs enabled, and (2) the foundational activity program costs on a Net Present Value (NPV) basis that are included in CBR calculations for enabled control or mitigation programs.

PG&E recently redefined several control and situational awareness programs as foundational activities. This includes most of its electric distribution and transmission inspection programs (i.e., ground, aerial, IR, climb) where the risk reduction work was funded and completed through an alternate program. Grid monitoring programs, such as line sensors, EFD, DFA, and Partial Voltage Detection were also redefined as foundational activities, because the intent of the programs is to identify the issue, with separate programs that focus on the resolution.

a. Inspection Programs

PG&E patrols and inspects its assets and facilities to identify damages and other conditions that may pose risks, including the risk of a wildfire ignition. Inspections programs help identify emergency/non-emergency corrective actions and are considered foundational, as they enable other wildfire control and mitigation programs.

- <u>WLDFR-C005 – Distribution OH Inspections – Ground</u>: Distribution OH Ground Inspections examine and record any abnormal conditions that may adversely impact safety or reliability, in accordance with GO 165 and the EDPM Manual. Ground inspections cover electric distribution facilities (including, but not limited to, PG&E-owned and joint-owned poles, primary and secondary conductors, risers, services, towers, etc.) and identify asset conditions that may have a higher likelihood of failure.
- <u>WLDFR-C006 – Distribution OH Inspections – IR</u>: The Distribution OH Inspections – IR Program uses infrared (IR) technology and cameras to identify hot spots or conditions that indicate potential

equipment failure. PG&E deploys IR inspections on an as-needed basis to examine areas of emerging concern to identify asset conditions, including those related to excess heat, that may lead to a failure and potentially an ignition.

- WLDFR-C007 – Distribution OH Inspections – Aerial: Distribution OH Aerial Inspections are conducted primarily using drones to capture the images, followed by completion of the inspection by a desktop inspector. In 2023, PG&E confirmed a larger scale deployment of the program (37,000 structures), while continuing to deliver a better view of pole tops and equipment. The program helps identify priority conditions that should be addressed, as well as asset conditions that may lead to an ignition.
- WLDFR-C011 – Intrusive Wood Pole Inspection Program: The Intrusive Wood Pole Inspection Program, also referred to as pole test and treat (PT&T), evaluates in service wood poles for early signs of deterioration and helps manage premature failure of wood pole structure due to internal rot or shell degradation. PT&T identifies wood poles across T&D wood pole structures that are nearing the end of their service life and recommends these poles for replacement or reinforcement prior to failure. PT&T prolongs the service life of wood poles through reapplication of preservative and/or restoration of structural strength through reinforcement, which mitigates against the potential for an ignition event.
- WLDFR-C013: Patrols – Distribution OH: Distribution OH Patrols are simple, visual examinations of applicable OH and UG facilities to identify obvious structural problems and hazards. These patrols may be executed on foot, by vehicle, or by aerial means, and are conducted across the system. Patrol inspections identify asset conditions that may lead to a failure and align with compliance requirements outlined in GO 165. This program has been enhanced since the prior RAMP filing by using two-person crews for patrol in areas that might pose a higher safety risk.
- WLDFR-C025: Transmission Inspections IR: Transmission IR Inspections are performed in HFTD/HFRA via helicopter and

conducted simultaneously with corona inspections to proactively identify asset conditions which could result in an ignition. IR inspections are timed with heavier load seasons to provide more accurate inspections.

- WLDFR-C028: Transmission Inspections Climbing: Climbing Inspections of Transmission structures are performed visually by an inspector climbing the structure to identify asset conditions which could lead to an ignition. Measurements are also taken for structures climbed with internal guy wires. PG&E conducts a climbing inspection on structures in the HFTD/HFRA that are 500 kV or contain internal guy wires at least once every three years. In addition to this baseline cycle, structures may also be added to the annual inspection scope based on Wildfire Risk profile or other factors, such as inspection result trends, terrain/fire suppression considerations, etc.
- WLDFR-C029: Transmission Inspections Aerial: Aerial Inspections of Transmission structures are performed in HFTD/HFRA via drone, helicopter, or aerial lift, in conjunction with a desktop image review. These inspections seek to identify asset conditions which could lead to an ignition. Similar to climbing inspections, structures may also be added to the annual inspection scope based on factors, such as the Wildfire Risk data.
- WLDFR-C030: Transmission Inspections Ground: Detailed Ground Inspections of OH electric transmission facilities are performed visually by an inspector on the ground to examine and record any abnormal conditions that will adversely impact safety or reliability for compliance with GO 165 and the ETPM Manual. Inspected facilities include PG&E solely and jointly-owned transmission structures and conductors.

b. Data Gathering and Continuous Monitoring

PG&E has deployed a suite of comprehensive data gathering and continuous monitoring programs, such as weather stations, wildfire cameras, and asset inspections. These programs provide insight into changing environmental hazards around our assets, as well as continuous monitoring capability that supports mitigation deployment.

- WLDFR-C010: Situational Awareness and Forecasting Initiatives – Early Fault Detection (EFD): EFD technology provides early detection of failing equipment and has the potential to detect vegetation encroachment. EFD sensors are a sophisticated technology that monitors the Radio Frequency signal that is generated by partial discharge arcing on AC circuits and uses precision time measurement of events to locate the source along the conductors. It has been successful in identifying incipient risks that have the potential to cause to wildfires if left unidentified / resolved in a timely manner, such as broken conductor, broken/melted insulators, cracked insulators, and broken tie wire.
- WLDFR-C012: Situational Awareness and Forecasting Initiatives – Distribution Fault Anticipation (DFA): DFA technology consists of substation-based devices measuring volts, amps, and arcing conditions. These devices provide detection and assistance locating faults, abnormal power flow events, and categorization of events.
- WLDFR-C023: Situational Awareness and Forecasting Initiatives – Line Sensors: Line Sensors are conductor-mounted devices that continuously measure current in real-time and report events as they occur, enabling proactive monitoring and identifying grid disturbances. In combination with DFA technology, Line Sensors can be used to locate OH failures, such as Fault Induced Conductor Slap.
- WLDFR-M005: Situational Awareness and Forecasting – Numerical Weather Prediction and Weather Stations: The Numerical Weather Prediction and Weather Stations Program consists of high-resolution weather modeling efforts that seek to produce accurate forecasts for preparedness and mitigation measures for upcoming weather threats. It also utilizes a weather station observation network to validate those threats.

Accurate weather model data and robust real-time observations enable preparation and execution of mitigation measures to reduce wildfire and outage duration risks. This program is critical to PSPS, EPSS, and the Storm Outage Prediction Project, enabling key models such as the PG&E FPI, Outage Probability Weather, and Ignition Probability Weather.

- WLDFR-M006: Situational Awareness and Forecasting Initiatives – Cameras: High definition (HD) Cameras are used by the CAL FIRE, USFS, PG&E, and other local agencies to identify, confirm, and track wildfires and general conditions (based on fire behavior and associated weather risks) in real-time.

  Wildfire cameras improve PG&E's overall situational awareness and are a valuable tool for assisting the HAWC, first responders, and fire agencies. These cameras allow PG&E employees and other stakeholders, including jurisdictional agencies, to be notified on early detections of potential wildfires, to monitor and assess the size and spread of an incipient wildfire, and to more rapidly deploy resources directly to areas where they can have the greatest impact.
- WLDFR-M007: Situational Awareness and Forecasting Initiatives – Satellite Fire Detection: The Satellite Fire Detections Programs improve, deploy, and maintain operational models that help PG&E predict the risk and consequence of fires. The advanced fire modeling included in the initiative is foundational to the PSPS and EPSS Programs and daily mitigation activities that reduce the risk of utility-caused ignitions, supporting projects that include the development of Dead and Live Fuel Moisture models, live fuel moisture sampling for field validation and calibration, fire spread model operations, improvements to the PG&E's machine learning FPI, and satellite fire detections.

c. Vegetation Management

Each year, PG&E inspects approximately 100,000 miles of lines, resulting in trimming or removing more than one million trees. It also addresses dead and dying trees. This effort includes different types of patrols designed to comply with state and federal laws and regulations that include FAC 003,[9] GO 95, Rule 35[10] and California PRC Section 4293.[11]

- WLDFR-C077: OneVeg Program: The One Veg Program provides a single, integrated platform with map-based work execution, monitoring, and validation for all vegetation management (VM) programs. The platform enables visibility into the vegetation work that has been prescribed or completed, allowing personnel to make informed decisions in the field and to identify necessary vegetation to mitigate risk.
- WLDFR-C078: Transmission Vegetation LiDAR: The Transmission Vegetation LiDAR program informs PG&E's transmission routine ground and second patrol control programs by inspecting approximately 18,000 miles on an annual cycle, including multiple ecological regions and jurisdictional boundaries. The annual LiDAR data collection identifies vegetation in proximity to electrical equipment that can cause an outage and/or ignition.

  The program supports VM patrol compliance with state and federal laws and regulations that includes: (1) FAC 003 (2) GO 95, Rule 35; (3) California PRC Section 4293.

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9 The purpose of this Federal regulation is to maintain a reliable electric transmission system by using a defense in-depth strategy to manage vegetation located on transmission rights of way (ROW) and minimize encroachments from vegetation located adjacent to the ROW, thus preventing the risk of those vegetation related outages that could lead to cascading outages.

10 Requires year-round clearance for power lines of a minimum 18 inches. Fire safety regulations require a minimum clearance of 4 feet (ft.) year-round for high-voltage power lines in the CPUC-designated HFTD areas. Rule 35 also requires the removal of known dead, diseased, defective, and dying trees that could fall into the lines.

11 Administered by CAL FIRE. It requires that PG&E maintain a 4 ft. minimum clearance for power lines between 2,400 volt (V) and 72,000 V, and a 10 ft. clearance for conductors 115,000 V and above. PRC 4293 states that dead, old, or rotten trees, trees weakened by decay or disease, and trees or portions thereof that are leaning toward the line which may contact the line from the side or may fall on the line shall be felled, cut, or trimmed so as to remove such hazard. This applies to the SRA during the designated fire season.

TABLE 1-22
FOUNDATIONAL ACTIVITIES

Line No.	Foundational Activity ID[(a)]	Foundational Activity Name	Foundational Activity Description	Enabled Control and Mitigation IDs[(a)]	2027-2030 millions of Dollars (NPV)[(b)]
1	DOVHD-C005, WLDFR-C005	Distribution Overhead Inspections – Ground	See description above	DOVHD-C014, WLDFR-C014, DOVHD-C019, WLDFR-C019, DOVHD-C020, WLDFR-C020, DOVHD-C021, WLDFR-C021, DOVHD-C022, WLDFR-C022	$20.69
2	DOVHD-C006, WLDFR-C006	Distribution Overhead Inspections – Infrared	See description above	DOVHD-C014, WLDFR-C014, DOVHD-C019, WLDFR-C019, DOVHD-C020, WLDFR-C020, DOVHD-C021, WLDFR-C021, DOVHD-C022, WLDFR-C022	3.76
3	DOVHD-C007, WLDFR-C007	Distribution Overhead Inspections – Aerial	See description above	DOVHD-C014, WLDFR-C014, DOVHD-C019, WLDFR-C019, DOVHD-C020, WLDFR-C020, DOVHD-C021, WLDFR-C021, DOVHD-C022, WLDFR-C022	145.82
4	WLDFR-C010	Situational Awareness and Forecasting Initiatives – EFD	See description above	DOVHD-C019, WLDFR-C019, DOVHD-C020, WLDFR-C020, DOVHD-C021, WLDFR-C021, DOVHD-C022, WLDFR-C022	19.20
5	DOVHD-C011, WLDFR-C011	Intrusive Wood Pole Inspection Program	See description above	DOVHD-C014, WLDFR-C014	124.75
6	WLDFR-C012	Situational Awareness and Forecasting Initiatives – DFA	See description above	DOVHD-C019, WLDFR-C019, DOVHD-C020, WLDFR-C020, DOVHD-C021, WLDFR-C021, DOVHD-C022, WLDFR-C022	8.23
7	DOVHD-C013, WLDFR-C013	Patrols – Distribution Overhead	See description above	DOVHD-C014, WLDFR-C014, DOVHD-C019, WLDFR-C019, DOVHD-C020, WLDFR-C020, DOVHD-C021, WLDFR-C021, DOVHD-C022, WLDFR-C022	16.20
8	WLDFR-C023	Situational Awareness and Forecasting Initiatives – Line Sensors	See description above	DOVHD-C019, WLDFR-C019, DOVHD-C020, WLDFR-C020, DOVHD-C021, WLDFR-C021, DOVHD-C022, WLDFR-C022	6.75

TABLE 1-22
FOUNDATIONAL ACTIVITIES
(CONTINUED)

Line No.	Foundational Activity ID[a]	Foundational Activity Name	Foundational Activity Description	Enabled Control and Mitigation IDs[a]	2027-2030 millions of Dollars (NPV)[b]
9	DOVHD-C023, WLDFR-C077	OneVeg Program	See description above	WLDFR-C001, DOVHD-C001, WLDFR-C002, DOVHD-C002, WLDFR-M027, DOVHD-M027, WLDFR-M028, DOVHD-M028, WLDFR-M029, DOVHD-M029, WLDFR-M030, DOVHD-M030	69.70
10	WLDFR-M005	Situational Awareness – Numerical Weather Prediction and Weather Stations	See description above	WLDFR-M001	11.30
11	WLDFR-M006	Situational Awareness and Forecasting Initiatives – Cameras	See description above	WLDFR-M001	22.31
12	WLDFR-M007	Situational Awareness and Forecasting Initiatives – Satellite Fire Detection	See description above	WLDFR-M001	0.47
13	DOVHD-M005	Additional Asset Data Captures	See description in Risk Mitigation Plan EO – DOVHD chapter	DOVHD-C014, WLDFR-C014, DOVHD-C019, WLDFR-C019, DOVHD-C020, WLDFR-C020, DOVHD-C021, WLDFR-C021, DOVHD-C022, WLDFR-C022	4.38
14	DOVHD-C008	Annual Protection Reviews	See description in Risk Mitigation Plan EO – DOVHD chapter	DOVHD-C014, WLDFR-C014, DOVHD-C019, WLDFR-C019, DOVHD-C020, WLDFR-C020, DOVHD-C021, WLDFR-C021, DOVHD-C022, WLDFR-C022	28.08
15		Total			$481.62

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

(b) NPV uses a base year of 2023.

For additional details see WP EO-WLDFR-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3. For System Hardening, Maintenance Tags and IGP-related programs, the cost estimates are based on the anticipated work forecasted over the forecast years which deviates from the 2024 budget.

D. 2027-2030 Proposed Control and Mitigation Plan

1. Changes to Controls

PG&E plans to continue the 2023-2026 controls described in Section C in 2027-2030. There are no major changes currently planned for these programs in 2027-2030, but PG&E will continue to evaluate programs to incorporate industry-wide standards that address extreme weather events and applicable lessons learned. As a result, PG&E may adjust the scope and cadence of these programs.

TABLE 1-23
CONTROL COST ESTIMATES, RISK REDUCTION AND CBR
2027-2030

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[b]			
Line No.	Control ID)[a]	Control Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[c] [C]/([A]+[B])
1	DOVHD-C001, WLDFR-C001	VM Distribution – Routine Patrols	$712,688	$714,555	$716,478	$718,459	$1,978	$43.0	$6,531	3.2
2	DOVHD-C002, WLDFR-C002	VM Distribution – Second Patrols	79,793	80,125	80,466	80,817	222	4.8	172	0.8
3	DOVHD-C009, WLDFR-C009	Overloaded Transformers Replacement	8,087	8,249	8,413	8,582	32	–	6	0.2
4	DOVHD-C014, WLDFR-C014	Pole Replacement	728,990	504,588	504,588	415,709	2,099	263.4	2,285	1.0
5	DOVHD-C015, WLDFR-C015	Overloaded Pole Replacements	12,019	12,019	12,019	12,019	46	–	1	<0.1
6	DOVHD-C016, WLDFR-C016	Animal Abatement [2AB,KAC]	3,666	3,666	3,666	3,666	14	–	246	18.0
7	DOVHD-C017, WLDFR-C017	Animal Abatement [2AC,KAD]	8,869	8,869	8,869	8,869	30	–	3,465	117.1
8	DOVHD-C018, WLDFR-C018	Pole Restoration	6,429	6,557	6,688	6,822	25	–	20	0.8

TABLE 1-23
CONTROL COST ESTIMATES, RISK REDUCTION AND CBR
2027-2030 EXPENSE
(CONTINUED)

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[b]			
Line No.	Control ID)[a]	Control Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[c] [C]/([A]+[B])
9	DOVHD-C019, WLDFR-C019	Emergency Distribution Replacements [17B]	98,510	98,510	98,510	98,510	378	35.6	46,108	111.4
10	DOVHD-C020, WLDFR-C020	Distribution Steady State Proactive Replacements [2AA]	107,042	182,753	182,753	212,571	647	61.0	1,983	2.8
11	DOVHD-C021, WLDFR-C021	Distribution Steady State Maintenance Replacements [KAA]	25,217	98,372	91,252	59,648	187	17.6	1,751	8.5

TABLE 1-23
CONTROL COST ESTIMATES, RISK REDUCTION AND CBR
2027-2030 EXPENSE
(CONTINUED)

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[b]			
Line No.	Control ID)[a]	Control Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[c] [C]/([A]+[B])
12	DOVHD-C022, WLDFR-C022	Distribution Steady State Maintenance Replacements [KAQ]	859	859	859	859	2	0.2	1	0.2
13		Total	$1,792,169	$1,719,121	$1,714,561	$1,626,531				

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

(b) NPV uses a base year of 2023.

(c) CBR calculations include allocated Foundational Activity program costs.

Note: For additional details see WP EO WLDFR F.

The cost estimates in this table are generally based on PG&E’s 2024 budget plan carried forward through 2030. See Exhibit (PG&E 1), Chapter 1, Section D.3. For System Hardening, Maintenance Tags and IGP-related programs, the cost estimates are based on the anticipated work forecasted over the forecast years which deviates from the 2024 budget.

2. Changes to Mitigations

PG&E continues to evaluate the effectiveness of implemented mitigations to tailor future mitigations that allow for faster deployment, provide long-term climate resilience across all weather scenarios, and aggressively phase out mitigations that are deemed less cost effective. In addition to traditional mitigations that PG&E has pursued, PG&E is planning on engaging public-private partnerships to lessen the consequences of catastrophic Wildfire Risk across California. As the understanding of the Wildfire Risk profile evolves, PG&E anticipates implementing new mitigations that are not currently in place.

The following mitigations are expected to not continue into the 2027-2030 time period:

- WLDFR-M003 – Non-Exempt Surge Arresters: This program is expected to address the known population prior to 2027.
- WLDFR-M004 – Expulsion Fuse Replacement. This program is expected to address the known population prior to 2027.
- WLDFR-M010 – Additional System Automation and Protection – FuseSavers: Deployment of other protection devices is being explored to support EPSS.
- WLDFR-M014 – Butte County Rebuild: This program is expected to be completed prior to 2027.

The following mitigation is expected to change into the 2027-2030 time period:

- WLDFR-M022 – System Hardening [UG]: PG&E's System Hardening Undergrounding Program that converts OH distribution lines and equipment to UG will include secondary and services.

The volume of mitigation work PG&E plans to complete over the 2027-2030 period is shown in Table 1-24 below.

TABLE 1-24
PLANNED MITIGATIONS 2027-2030

Line No.	Mitigation ID[(a)]	Mitigation Name	Planned Units of Work					
			Unit of Measurement[(b)]	2027	2028	2029	2030	Total
1	DOVHD-M002, PCEEE-M002, WLDFR-M002	System Hardening [Overhead]	Miles	90	90	90	90	360
2	WLDFR-M008	Safety Infrastructure Protection Teams[(b)]	Poles	2,720	2,720	2,720	2,720	10,880
3	WLDFR-M011	System Hardening [Remote Grid]	Miles	10	10	10	10	40
4	DOVHD-M022, PCEEE-M003, WLDFR-M022	System Hardening [Underground]	UG Miles	329	395	461	526	1,711
5	DOVHD-M023, WLDFR-M023	Backlog Open Tag Reduction – Distribution (Pole Backlog)	Pole Notifications	1,780	2,905	3,501	16,358	24,544
6	DOVHD-M024, WLDFR-M024	Backlog Open Tag Reduction – Distribution (Capital) [2AA]	Capital Non-Pole Notifications	4,482	1,559	2,009	14,991	23,041
7	DOVHD-M025, WLDFR-M025	Backlog Open Tag Reduction – Distribution (Expense) [KAA]	Expense Non-Pole Notifications	41,850	9,405	11,189	53,491	115,935
8	DOVHD-M026, WLDFR-M026	Pole Programs – Replace Tree Attachments	Poles	979	979	979	979	3,918
9	DOVHD-M027, WLDFR-M027	Pole Clearing	Poles	65,000	65,000	65,000	65,000	260,000
10	DOVHD-M028, WLDFR-M028	VM Distribution – Focused Tree Inspections(c)	Miles	1,788	1,788	1,788	1,788	7,153
11	DOVHD-M029, WLDFR-M029	VM Distribution – Operational Improvements	Trees	16,646	16,646	16,646	16,646	66,584

TABLE 1-24
PLANNED MITIGATIONS 2027-2030
(CONTINUED)

Line No.	Mitigation ID[a]	Mitigation Name	Planned Units of Work: Unit of Measurement[b]	2027	2028	2029	2030	Total
12	DOVHD-M030, WLDFR-M030	Vegetation Management – Tree Removal	Trees	44,488	44,488	44,488	44,488	177,953
13	WLDFR-M035	Integrated Vegetation Management – Transmission	Acres	6,504	6,504	6,504	6,504	26,016
14	WLDFR-M037	Substation Distribution – Defensible Spaces	Number of Substations	189	189	189	189	756
15	WLDFR-M039	Substation Transmission – Defensible Spaces	Number of Substations	82	82	82	82	328
16	DOVHD-M031, WEPSS-M011, WPSPS-M003	Portable Battery	# Batteries	2,953	2,658	2,392	2,152	10,155
17	DOVHD-M032, WEPSS-M012, WPSPS-M004	Permanent Battery	# Batteries	1,000	1,000	1,000	1,000	4,000
18	DOVHD-M033, WEPSS-M013, WPSPS-M005	RSI Battery	# Batteries	1,300	1,300	1,300	1,300	5,200

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

(b) The units of work are presented as used in the RAMP model because the model requires that units of work are standardized. These may differ in some instances from "rate case" units – the units referred to in PG&E's General Rate Case or other proceedings.

(c) Based on the approved PG&E 2023-2025 WMP, VM Distribution – Focused Tree Inspections has transitioned to 1,500 miles/year.

Note: For additional details see WP EO-WLDFR-F.

Tables 1-25 and 1-26 detail the cost estimates, risk reduction values, and CBRs for each of the Wildfire Risk mitigations PG&E plans to implement in the 2027-2030 period. The derivation of CBRs and risk reduction values is explained in Exhibit (PG&E-2), Chapter 2.

TABLE 1-25
MITIGATION COST ESTIMATES, RISK REDUCTION, CBR, AND FACTORS AFFECTING SELECTION
2027-2030 EXPENSE

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[b]				
Line No.	Mitigation ID[a]	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[c] [C]/([A]+[B])	Factors Affecting Selection
1	WLDFR-M008	Safety Infrastructure Protection Teams	$15,737	$15,737	$15,737	$15,737	$47	–	$268	5.7	
2	WLDFR-M020	EPSS	61,612	61,612	61,612	61,612	481	–	24,975	51.9	
3	WLDFR-M001	PSPS	39,533	39,533	39,533	39,533	119	34.1	6,564	42.8	
4	DOVHD-M025, WLDFR-M025	Backlog Open Tag Reduction – Distribution (Expense) [KAA]	86,450	19,428	23,113	110,496	164	–	1,089	6.6	
5	DOVHD-M027, WLDFR-M027	Pole Clearing	24,695	23,460	22,287	21,173	64	1.4	147	2.3	
6	DOVHD-M028, WLDFR-M028	VM Distribution – Focused Tree Inspections	220,976	221,334	221,702	222,082	612	13.3	3,371	5.4	
7	DOVHD-M029, WLDFR-M029	VM Distribution – Operational Improvements	20,910	20,910	20,910	20,910	58	1.3	300	5.1	
8	DOVHD-M030, WLDFR-M030	Vegetation Management – Tree Removal	98,075	98,075	98,075	98,075	271	5.9	1,374	5.0	

TABLE 1-25
MITIGATION COST ESTIMATES, RISK REDUCTION, CBR, AND FACTORS AFFECTING SELECTION
2027-2030 EXPENSE
(CONTINUED)

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[b]				
Line No.	Mitigation ID[a]	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[c] [C]/([A]+[B])	Factors Affecting Selection
9	WLDFR-M035	Integrated Vegetation Management - Transmission	13,385	13,385	13,385	13,385	37	–	157	4.2	
10	WLDFR-M037	Substation Distribution – Defensible Spaces	1,715	1,715	1,715	1,715	5	–	0	<0.1	WMP
11	WLDFR-M039	Substation Transmission – Defensible Spaces	880	880	880	880	2	–	0	<0.1	WMP
12	DOVHD-M031, WEPSS-M011, WPSPS-M003	Portable Battery	9,180	8,263	7,436	6,690	22	–	95	4.3	
13	DOVHD-M032, WEPSS-M012, WPSPS-M004	Permanent Battery	5,300	5,300	5,300	5,300	15	–	200	13.7	
14	DOVHD-M033, WEPSS-M013, WPSPS-M005	RSI Battery	23,208	23,208	23,208	23,208	64	–	260	4.1	

TABLE 1-25
MITIGATION COST ESTIMATES, RISK REDUCTION, CBR, AND FACTORS AFFECTING SELECTION
2027-2030 EXPENSE
(CONTINUED)

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[b]				
Line No.	Mitigation ID[a]	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[c] [C]/([A]+[B])	Factors Affecting Selection
15	WPSPS-M006	Temporary Generation	8,713	8,713	8,713	8,713	24	–	56	2.3	
16		Total	$630,369	$561,553	$563,607	$649,509					

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.
(b) NPV uses a base year of 2023.
(c) CBR calculations include allocated Foundational Activity program costs.
Note: For additional details see WP EO-WLDFR-F.
The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E 1), Chapter 1, Section D.3. For System Hardening, Maintenance Tags and IGP related programs, the cost estimates are based on the anticipated work forecasted over the forecast years which deviates from the 2024 budget.

TABLE 1-26
MITIGATION COST ESTIMATES, RISK REDUCTION, CBR, AND FACTORS AFFECTING SELECTION
2027-2030 CAPITAL

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[b]				
Line No.	Mitigation ID[a]	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[c] [C]/([A]+[B])	Factors Affecting Selection
1	DOVHD-M002, PCEEE-M002, WLDFR-M002	System Hardening [Overhead]	$112,118	$115,481	$118,946	$122,514	$449	–	$7,987	17.8	
2	WLDFR-M008	Safety Infrastructure Protection Teams[b]	561	561	561	561	47	–	268	5.7	
3	WLDFR-M011	System Hardening [Remote Grid]	12,900	12,900	12,900	12,900	50	–	1,035	20.9	
4	WLDFR-M020	EPSS	44,822	44,887	44,952	45,020	481	–	24,975	51.9	
5	WLDFR-M001	PSPS	1,458	1,458	1,458	1,458	119	34	6,564	42.8	
6	DOVHD-M022, PCEEE-M003, WLDFR-M022	System Hardening [Underground]	1,320,501	1,575,164	1,852,955	2,139,167	6,483[d]	–	51,323	7.9	
7	DOVHD-M023, WLDFR-M023	Backlog Open Tag Reduction – Distribution (Pole Backlog)	31,260	51,016	61,483	287,273	389	–	41	0.1	Compliance
8	DOVHD-M024, WLDFR-M024	Backlog Open Tag Reduction – Distribution (Capital) [2AA]	46,631	16,220	20,902	155,968	220	–	165	0.8	Compliance

TABLE 1-26
MITIGATION COST ESTIMATES, RISK REDUCTION, CBR, AND FACTORS AFFECTING SELECTION
2027-2030 CAPITAL
(CONTINUED)

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[b]				
Line No.	Mitigation ID[a]	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[c] [C]/([A]+[B])	Factors Affecting Selection
9	DOVHD-M026, WLDFR-M026	Pole Programs – Replace Tree Attachments	18,303	18,303	18,303	18,303	127	–	5	<0.1	Modeling limitations
10		Total	$1,588,553	$1,835,990	$2,132,460	$2,783,162					

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.
(b) NPV uses a base year of 2023.
(c) CBR calculations include allocated Foundational Activity program costs.
(d) NPV of Program Cost includes a NPV of very rough estimates of OpEx savings (as a negative value) to consider potential lifetime OpEx savings in the CBR calculation.

Note: For additional details see WP EO-WLDFR-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3. For System Hardening, Maintenance Tags and IGP-related programs, the cost estimates are based on the anticipated work forecasted over the forecast years which deviates from the 2024 budget.

3. Changes to Foundational Activities

PG&E plans to continue the 2023-2026 foundational programs in 2027-2030. There are not any major changes currently planned for these programs in 2027-2030, but PG&E will continue to evaluate them and incorporate lessons learned. As a result, PG&E may adjust the scope and cadence of the foundational programs. Over the course of 2027 and beyond, PG&E would also like to evaluate and incorporate the utilization of artificial intelligence and other emerging technology capabilities to improve upon these foundational programs.

4. Factors Affecting Mitigation Selection

- <u>WMP Commitments</u>: The Substation Distribution – Defensible Spaces and Substation Transmission – Defensible Spaces mitigation program CBRs are a result of substations having a low ignition risk and accounting for less than 1 percent of PG&Es overall Wildfire Risk. However, this is the best defense of preventing an ignition coming from equipment failure spreading outside the fence line and vegetation coming in contact into substation equipment. Defensible space programs exist as part of our 2023-2025 WMP commitment.
- <u>Compliance Requirements</u>: PG&E continues to work down the notification backlog as part of our compliance requirements and the 2023-2025 WMP commitment. Backlog Open Tag Reduction - Distribution (Pole Backlog) and Backlog Open Tag Reduction – Distribution (Capital) [2AA] focus on addressing the backlog of pole maintenance tags and capital equipment maintenance tags that are currently associated to PG&E assets. Remediation of these tags address risk associated to Wildfire and the risk associated to Failure of Electric Distribution Overhead Assets. Due to this backlog mitigation being addressed by addressing high risk locations first, by the end of the program, the risk reduction associated with these notifications are less risky but still required as a compliance requirement. These programs are required as part of compliance with GO 95.
- <u>Modeling Limitations</u>: The Pole Programs - Replace Tree Attachments program utilizes a tree as a support structure, limbs on the tree need to

be removed to avoid contact, which, in turn, has an impact to tree health. If the tree dies, it poses a threat as both a pole failure and a potential vegetation strike. PG&E subject matter experts (SME) believe that the low CBR score generated by the risk model is due to data limitations, that is, limited data on tree attachment failures. PG&E will continue to remove tree attachments from dead or dying trees.

E. Alternative Mitigations Analysis

In addition to the mitigations discussed above, PG&E considered alternative mitigations that could be deployed in the future. PG&E describes each of the alternative mitigations and then provides a table that includes the cost estimates, risk reduction values, and CBRs for each of the Alternative Plans.

1. Alternative Plan 1: WLDFR-A001/WPSPS-A001 – System Hardening [UG]

PG&E considered an alternative to the approach for System Hardening [UG] program (WLDFR-M022) described in Section C. In the alternative proposal, PG&E considered a workplan that only mitigates Primary cable risk through Undergrounding, with Secondary and Service cable risk being mitigated through OH Hardening. The alternative workplan would perform fewer undergrounded miles per year after 2027 (i.e., 2027-500 miles, 2028-550 miles, 2029-600 miles, and 2030-650 miles), lowering the total cost of the program, and would have a CBR of 9.7. This would allow for additional budget to be allocated towards other electric programs, primarily addressing the backlog of identified pole tags.

The decision to not proceed with this proposal is due to multiple factors. Budget re-allocation to pole tag programs would not provide an incremental risk reduction benefit, and the undergrounding of Secondary and Service lines provide additional benefits that are not as easily quantified, such as improvements to PSPS, end of line reliability, and customer satisfaction.

TABLE 1-27
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[b]		
Line No.	Mitigation ID[a]	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	DOVHD A001, PCEEE A003, WLDFR A001	System Hardening [Underground] (Alternative Workplan)	$1,459,940	$1,571,705	$1,714,569	$1,861,676	$6,261.3[c]	$60,725.9	9.7
2		Total	$1,459,940	$1,571,705	$1,714,569	$1,861,676			

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

(b) NPV uses a base year of 2023.

(c) NPV of Program Cost includes a NPV of very rough estimates of OpEx savings (as a negative value) to consider potential lifetime OpEx savings in the CBR calculation.

Note: For additional details see WP EO-WLDFR-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3. For System Hardening, Maintenance Tags and IGP-related programs, the cost estimates are based on the anticipated work forecasted over the forecast years which deviates from the 2024 budget.

2. Alternative Plan 2: WLDFR-A002 – Grid Monitoring

PG&E maintains a wide range of grid operation monitoring, which provides greater visibility into the system for operational mitigations. Additional needs for grid monitoring occur through a risk-informed SME assessment of potential monitoring systems that could further reduce risk. New technologies that can expand existing capabilities are also evaluated across potential quantitative performance and risk reduction metrics. This alternative plan considers the implementation of several line and pole mounted technologies to address high priority threats on the distribution system that lack real-time condition monitoring. These threats include:

- Time-dependent threats;
- Vibrations causing high-cycle fatigue on insulators & crossarms, which can result in failures at connectors and splices;
- <u>Hazards</u>:
  - First-, second-, third-party damage and vandalism on wood/non-wood poles;
  - Vegetation growth and encroachment on conductors/insulators/cross-arms;
  - Weather/outside forces on conductors/insulators/cross-arms; and
  - Wind effects on cross-arm and wood/non-wood poles.

CBR estimates are based on an assumed effectiveness and deployment in HFTD CPZs where there is currently not a high penetration of existing sensors (i.e., Line Sensors/EFD/DFA).

This program was not included in the base mitigation plan due to the additional analysis required to implement failure probabilities based on sensor data. The volume of data required to identify and appropriately manage the likelihood of failure is significant, as it will require testing and alignment to both equipment and environmental conditions. Moving forward, PG&E is considering piloting sensor programs to help provide this data and additional understanding.

TABLE 1-28
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[b]		
Line No.	Mitigation ID[a]	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	DOVHD A002, WLDFR A002	Grid Monitoring (Alternative Mitigation)	$12,634	$12,878	$12,582	$12,170	$87.1	$600.2	6.9
2		Total	$12,634	$12,878	$12,582	$12,170			

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

(b) NPV uses a base year of 2023.

Note: For additional details see WP EO-WLDFR-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3. For System Hardening, Maintenance Tags and IGP-related programs, the cost estimates are based on the anticipated work forecasted over the forecast years which deviates from the 2024 budget.

3. Alternative Plan 3: WLDFR-A003 – Line Slap

The third alternative plan considers the impact of line slap and reconfiguring conductor attachments. Power lines are designed with enough clearance distance between the lines to keep the lines or conductors from contacting under normal operating conditions. However, unusual circumstances, such as wind events, occur that may cause conductors to slap together. This is called "conductor slap" where high-energy arcing may occur and possibly result in hot metal particles falling to the ground and potentially igniting fuel such as dry vegetation.

PG&E conducted a study using LiDAR data-based methodology and FEA modeling to identify locations in our system where conductor-line slapping was most probable. The assessment identified roughly 33,000 spans that were at higher risk. Mitigation of line slapping includes reconfiguration of conductor attachments on poles to reduce eliminate the probability of this occurrence. The below results reflect mitigation of our highest 33,000 spans in HFTD/HFRA.

Since line slap represents small number of events, additional review and analysis is requited to determine if this is a viable program to deploy.

TABLE 1-29
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[b]		
Line No.	Mitigation ID[a]	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	WLDFR A003	Line Slap (Alternative Mitigation)	$5,109	$5,035	$4,998	$5,101	$35.1	$1.7	<0.1
2		Total	$5,109	$5,035	$4,998	$5,101			

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

(b) NPV uses a base year of 2023.

Note: For additional details see WP EO-WLDFR-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3. For System Hardening, Maintenance Tags and IGP-related programs, the cost estimates are based on the anticipated work forecasted over the forecast years which deviates from the 2024 budget.

4. Alternative Plan 4: WLDFR-A004 – Wildfire Resilience Partnerships – Fuels Treatment

Given that differing parts of PG&E's service area have differing locational Wildfire Risk drivers, including fuel loading, ingress/egress, and varying degrees of fire suppression capacity, PG&E is considering an alternative plan to catalyze targeted community and forest fire resilience aligned with locational risk drivers. The plan considers different forms of resilience partnerships which PG&E is exploring, including facilitating fuels management within utility rights of way along likely wildfire pathways, creating expanded fuel breaks beyond designated rights of way, improving community and forest wildfire defenses, facilitating or co-funding roadside clearing under rights of way along key ingress/egress routes, and collaborative wood management.

These targeted resilience partnerships can increase public wildfire safety and provide community-wide resilience. PG&E is not the only contributor to the funding of these partnerships. PG&E's partial co-investments and grants often provide operating entities an opportunity to pursue other external funding sources to expand and amplify the benefits of their programs.

In 2023, PG&E started piloting several initiatives with nonprofit organizations and other entities to help drive localized landscape-scale treatment in fuels-driven risk locations. The treatment strategies include mechanical thinning, controlled burns, and/or ecologically-appropriate reforestation (post-fire) and result in strengthened forest ecosystem health, and improved health of larger, stronger, ecologically-appropriate and fire-adapted trees.

PG&E will continue to form new community partnerships and co-develop projects and measure the associated Wildfire Risk reduction.

TABLE 1-30
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[b]		
Line No.	Mitigation ID[a]	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	WLDFR A004	Wildfire Resilience Partnerships – Fuels Treatment (Alternative Mitigation)	$300	–	–	–	$0.2	$5.0	21.7
2		Total	$300	–	–	–			

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

(b) NPV uses a base year of 2023.

Note: For additional details see WP EO-WLDFR-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3. For System Hardening, Maintenance Tags and IGP-related programs, the cost estimates are based on the anticipated work forecasted over the forecast years which deviates from the 2024 budget.

PACIFIC GAS AND ELECTRIC COMPANY

RISK ASSESSMENT AND MITIGATION PHASE

CHAPTER 2

RISK ASSESSMENT AND MITIGATION STRATEGY: ELECTRIC TRANSMISSION SYSTEMWIDE BLACKOUT

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RISK ASSESSMENT AND MITIGATION STRATEGY: ELECTRIC TRANSMISSION SYSTEMWIDE BLACKOUT

A. Executive Summary

The Electric Transmission Systemwide Blackout (BLKOT) risk is defined as the risk of a systemwide disturbance leading to a cascading event that causes a blackout of Pacific Gas and Electric Company's (PG&E) electrical system, with the inability to restore the grid in a timely fashion. This is the first year that PG&E has included Electric BLKOT as a Risk Assessment and Mitigation Phase (RAMP) risk. While PG&E has not experienced a cascading BLKOT event, other utilities across North America and California have experienced a BLKOT event in the last 20 years. Electric BLKOT has the fourth-highest 2027 Test Year (TY) Baseline Safety Risk Score ($51.8 million) and the third-highest 2027 TY Baseline Total Risk Score ($1.9 billion) of PG&E's 32 Corporate Risk Register risks.

BLKOT covers PG&E's entire transmission network and downstream distribution assets in the event of a cascading blackout. Drivers for the risk event reflect a combination of events and consist of: Grid Emergency & Natural Hazard; Grid Emergency & Utility Operation; Grid Emergency & Third-Party; Grid Emergency & Other; and Domestic Violent Extremists (DVE). Grid Emergency events account for 63 percent of the overall risk. A coordinated and sustained attack on specific Critical Infrastructure Protection (CIP) assets by DVEs accounts for 37 percent of the remaining risk. Exposure to this risk is based on the complete loss of load for all PG&E customers (5.7 million) for an extended outage lasting at least 2-3 days.

Consequence for BLKOT is primarily driven by reliability impacts, with the outcomes reflecting a loss of load for all PG&E customers associated with (and not associated with) cyber attacks. Loss of load not associated with cyber attacks accounts for 99 percent of the overall risk and frequency, which reflects a consequence of risk event value of $284.68 billion.

PG&E’s transmission system structure has multiple redundancies and controls in place to prevent an outage from spreading in a cascading event that may affect the entire grid, though there are no mitigations planned for these driver events other than existing controls. PG&E does have several independent controls and some in conjunction with the California Independent System Operator (CAISO) that have proved effective in preventing a BLKOT event.

Alternative mitigation strategies were also considered to address this risk, focusing on site hardening and additional situational awareness personnel. Site hardening considers security improvements to reduce the likelihood of successful DVE attacks. The plan for additional situational awareness personnel expands capabilities to improve existing monitoring and to strengthen response readiness.

The controls, mitigations, and alternatives for addressing this risk event are further described in Sections C, D, and E of this chapter.

1. Risk Overview

TABLE 2-1
RISK DEFINITION, SCOPE, AND DATA SOURCES

Line No.	Risk Name	Electric Transmission Systemwide Blackout
1	Definition	A system wide disturbance leading to a cascading event that causes a blackout of PG&E’s electrical system, with the inability to restore the grid in a timely fashion.
2	In Scope	A single outage or combination of outages on the transmission that lead to a complete systemwide outage.
3	Out of Scope	Outages (including cyber attack) that affect multiple regions or divisions of PG&E territory but do not lead to system wide outage. Rotating blackouts (i.e., the term used when each set of distribution feeders is interrupted for a limited time, typically 20–30 minutes, and then those feeders are put back in service and another set is interrupted, and so on, rotating the outages among individual feeders). Storm events that affect PG&E assets over the course of multiple days through multiple territory do not qualify as cascading blackouts.
4	Data Quantification Sources	Data associated with the drivers/source of failures and data associated with reliability impact of failures are taken from PG&E’s Distribution Overhead Outage Dataset from January 1, 2015 to December 31, 2019. Data associated with the safety consequences of failures is taken from PG&E’s Electric Incident Reports from January 1, 2015 to December 31, 2019. Data associated with the financial impact of failures is taken from PG&E’s DOH Restoration Costs Dataset from January 1, 2017 to September 30, 2019.

B. Risk Assessment

1. Background and Evolution

Uncontrolled cascading blackouts in the United States have occurred in the Northeast in 1965 and 2003. Similarly, blackouts have occurred in the Southwest (Southern California, Arizona, and Mexico) in 2011.

While PG&E has not experienced a cascading event rooted from a transmission equipment failure, PG&E has experienced smaller events that have resulted in load shedding. On December 22, 1982, hurricane force winds in Tracy, California knocked over a 500 kilovolts (kV) transmission tower that fell into a parallel transmission tower. The downed transmission towers created a domino effect, causing additional towers on each transmission line to mechanically fail, resulting in a total of six downed transmission towers. While PG&E was able to manage the outages within the PG&E territory by load shedding customers in southern San Jose, the effects were felt by Arizona and Nevada. More than 2 million customers across California, Nevada, and Arizona experienced a loss of electricity from the collapsed transmission towers and load unbalancing; however, this event was not determined to be a cascading event.

The most well-known cascading blackout event occurred across the northeastern United States on August 14, 2003, resulting in a combination of electrical vegetation contact, faults in the computer Energy Management System, and human error that led to the loss of power to 50 million customers and the indirect deaths of 90 people. The 90 indirect deaths were largely caused by exposure and carbon monoxide poisoning. This event also led to significant changes in the regulating of Bulk Electrical Systems (BES) and mitigations of future cascading events.

Today, PG&E’s system has built in controls designed to prevent the risk event (a cascading blackout) from occurring. Regulatory agencies, such as Federal Energy Regulatory Commission, North American Electric Reliability Corporation (NERC), Western Electricity Coordinating Council (WECC), and CAISO, have already instituted procedures and policies to prevent a cascading blackout. This includes redundant Grid Control Centers, where situational awareness is maintained of the BES by highly-trained operators capable of conducting load curtailment, and coordination with CAISO/WECC to maintain the grid. In the unlikely event of a cascading blackout, PG&E also has independent Blackstart Resources to restart the electrical grid.

2. Risk Bowtie

Figure 2-1 represents the overall Transmission Systemwide Blackout risk across the PG&E system territory and has a 2027 TY Baseline Risk Score of $1,903 million.

FIGURE 2-1
RISK BOWTIE

Drivers

	Freq (Events/Yr)	% Freq	% Risk
Domestic Violent Extremists	0.0025	38%	37%
Grid Emergency & Natural Hazard	0.0020	30%	30%
Grid Emergency & Utility Operation	0.0013	20%	20%
Grid Emergency & Third Party	0.0006	9%	10%
Grid Emergency & Other	0.0002	3%	3%
Aggregated	**0.00665**	100%	100%

Exposure
1
System

Transmission System-wide Blackout

TY Baseline
Risk Value
for 2027
$1,903M
(2023 $, risk-adjusted)

Outcomes

	CoRE	%Freq	%Risk
Loss of load for all PG&E customers / Not Associated with Cyber Attack	284,683	99%	99%
Loss of load for all PG&E customers / Associated with Cyber Attack	481,787	1%	1%
Aggregated	**286,283**	100%	100%

3. Exposure to Risk

PG&E’s exposure to this risk event is based upon its electric transmission system, which consists of transmission overhead, transmission underground, and transmission substations, that serve over 5.7 million customers. Exposure to the BLKOT risk is modeled on the loss of load for all PG&E customers and is represented by a unit count of 1, as the event reflects a binary situation. Should a systemwide blackout occur, loss of load is assumed to occur for the entirety of the system.

4. Tranches

PG&E has reviewed NERC reports for causes of cascading systemwide blackouts and non-cascading widespread blackouts across North America since 1965. From these reports, it was determined that three primary elements contributed to cascading outages; these outages spread uncontrollably throughout the BES system and had ripple effects across interconnects. The primary elements broke down into a utility's inability to respond to a grid emergency (which would limit the ripple effects of a cascading nature outage), multiple asset failures across the transmission systems, and lack of generation and increased demand on the BES for which ISO and the utility could not compensate for.

When discussing what PG&E transmission assets are more likely to lead to a cascading systemwide outage, PG&E is reluctant to discuss the criticality of specific transmission assets in open settings, due to the increased national trend of DVE attacks. PG&E does have a system in accordance with NERC CIP policies. Openly discussing what specific assets that are more likely to lead to a cascading blackout would provide a roadmap to a BLKOT by that could be used by bad actors in physical and cyber domains. As such, PG&E has identified one tranche associated with the BLKOT risk, which is the entire system of transmission network and downstream distribution assets.

5. Drivers and Associated Frequency

PG&E identified five drivers for the BLKOT risk. Each driver and its associated 2027 TY estimated frequency is discussed below.

A grid emergency is declared by CAISO regarding the state of the California grid and can also reflect adverse operating conditions across WECC. It involves 10 states and consists of Restricted Maintenance Operations, Transmission Emergency, Flex Alert, Energy Emergency Alert (EEA) Watch, EEA1, EEA 2, and EEA3 conditions. For PG&E, a grid emergency must already exist for a Natural Hazard, Utility Operation, Third Party, or Other event to have a significant enough impact on the electrical grid to lead to a cascading systemwide outage. A grid emergency is modeled to be present in 62 percent of the risk events and represents 63 percent of the risk.

- D1 – Domestic Violent Extremists: This driver is defined as United States-based actors who, without direction or inspiration from a foreign terrorist group or foreign power, seek to further political or social goals through unlawful acts of violence. This driver is distinct from the Physical Attack cross-cutting factor driver, as the motives of DVEs are more aligned to domestic terrorism; DVE attacks are either a coordinated, simultaneous attack against transmission assets or are designed to have a cumulative effect. DVE represents 38 percent of the risk events.
- D2 – Grid Emergency & Natural Hazard: This driver includes failure events caused by natural hazards, such as earthquakes, wildfires, lightning, flood, ice or snow, and heat wave, when there is already an existing grid emergency declared by CAISO. The Grid Emergency & Natural Hazard driver accounts for 30 percent of risk event frequency.
- D3 – Grid Emergency & Utility Operation: This driver includes failure events caused by PG&E employees based on lack of situational awareness of the grid, operating error, human performance, or other actions, when a grid emergency had already been declared. The Grid Emergency & Utility Operation driver accounts for 20 percent of the risk event frequency.
- D4 – Grid Emergency & Third Party: This driver includes failure events caused by third parties, such as aircraft strikes, vandalism, cyber attacks, sabotage, and public appeals (to and by the government to reduce electricity use). The Grid Emergency & Third Party driver

accounts for 9 percent of the risk event frequency and 10 percent of the risk.

- D5 – Grid Emergency & Other: The Grid Emergency and Other driver accounts for unexpected transmission interruptions, utility islanding, load shedding, voltage reductions, and public appeal to and by government officials to reduce electricity usage along the grid. This driver accounts for 3 percent of the risk event frequency and risk.

6. Climate Adaptation Vulnerability Assessment Results

PG&E designed the Climate Adaptation Vulnerability Assessment (CAVA) to be consistent with the California Public Utilities Commission's (CPUC) Final Ruling on Order Instituting Rulemaking (R.) to Consider Strategies and Guidance for Climate Change Adaptation (R.18-04-019). The methodology outlined by Decision 20-08-046 requires utilities to perform an assessment of all assets, operations and services that will be impacted by future risks from climate change related to changes in temperatures, precipitation & flooding, sea level rise, wildfire, and drought driven subsidence.

PG&E did assess through CAVA the impact to PG&E's transmission assets,[1] but did not assess future climate hazard impacts and climate risks specifically associated with a BLKOT event.

7. Cross-Cutting Factors

A cross-cutting factor is a driver, component of a driver, or a consequence multiplier that impacts multiple risks. PG&E is presenting seven cross-cutting factors in the 2024 RAMP. As shown in Table 2-2 below, all seven cross cutting factors impact the risk event, three of which—Cyber Attack, Physical Attack, and Seismic—have been captured in the documentation supporting nationwide Department of Energy OE-417 and are explicitly quantified as risk drivers. The fourth, Climate Change, is quantified, as described below.

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[1] PG&E's Climate Adaptation Vulnerability Assessment, Section 3.1.1.a Electric Transmission (to be published May 15, 2024).

TABLE 2-2
CROSS-CUTTING FACTORS SUMMARY

Line No.	Cross-Cutting Factor	Impacts Likelihood	Impacts Consequence
1	Climate Change	Yes	Yes*
2	Cyber Attack	Yes	Yes*
3	Emergency Preparedness and Response (EP&R)	No	Yes*
4	Information Technology Asset Failure	Yes*	Yes*
5	Physical Attack	Yes	No
6	Records and Information Management (RIM)	Yes*	No
7	Seismic	Yes	No

Yes The cross-cutting factor has been quantified in the model.

Yes* The cross-cutting factor does influence the baseline risk but has not been quantified in the model, or the cross-cutting factor may influence the baseline risk but further study is needed.

No The cross-cutting factor does not meaningfully influence the baseline risk.

A description of the cross-cutting factors, as well as the mitigations and controls that PG&E is proposing to mitigate the cross-cutting factors, is in Exhibit (PG&E-2), Chapter 3.

a. Climate Change

PG&E incorporates escalating event frequency over time due to three natural hazards: extreme heat events, extreme rain events (e.g., atmospheric rivers), and wildfire. Extreme heat events are defined as events where maximum temperatures exceed a certain threshold for multiple days (where the threshold and the duration vary by location). The escalation factor for BLKOT is estimated based on the frequency with which 2022 extreme heat event magnitudes (threshold, duration) are expected to happen in the future. As extreme heat events affect Grid Emergency conditions, PG&E escalates the likelihood of any Grid Emergency driver (excluding storm).

Extreme rain events are defined as the number of Major Rain Event Days per year due to Atmospheric River (AR) Storms. The escalation factor is estimated based on a study of United States West Coast AR Storms and is applied to the Grid Emergency & Storm subdriver.

Finally, wildfire presents a risk to transmission assets. PG&E used decadal fire frequency for key 500 kV transmission lines and aggregated those over the service territory to estimate how wildfire is likely to impact those transmission assets over time. The escalation factor is applied to the Grid Emergency & Wildfire subdriver.

8. Consequences

The BLKOT Bow Tie consists of two outcomes for a cascading blackout: (1) Loss of Load to All PG&E Customers Not Associated with Cyber Attack; and (2) Loss of Load to All PG&E Customers Associated with Cyber Attack. In the event of a cascading systemwide blackout, PG&E anticipates financial impacts, electrical reliability interruptions, and indirect public safety consequences.

Based off the historical review of systemwide blackouts, PG&E believes indirect safety consequences may correlate with exposure of the elements (extreme heat or extreme cold) and carbon-monoxide poisoning. PG&E assumes approximately six fatalities per billion Customer Minute Interruptions as described in Exhibit (PG&E-2) Chapter 2, Section C.2.a. Extreme heat or extreme cold conditions can exacerbate the potential safety impact. This is due to customers being unable to properly heat themselves (possibly leading to hypothermia over time) or cool themselves (possibly leading to heat stroke). During temperate weather conditions, it is also important to note it is possible to have no fatalities, as the risk to exposure is significantly lower and other cascading blackout events (2011 Southwest blackout) resulted in no direct or indirect fatalities.

Table 2-3 below shows the consequence of a BLKOT risk event. Model attributes are described in Exhibit (PG&E-2), Chapter 2.

TABLE 2-3
RISK EVENT CONSEQUENCES

			Natural Units Per Event			Monetized Levels (2023 $M) of a Consequence Per Event			CoRE			Natural Units per Year			Expected Loss per Year (2023 $M/yr)			Attribute Risk Score (2023 $M/yr, risk-adjusted)		
	CoRE | %Freq | %Risk	Freq	Indirect Safety EF/event	Electric Reliability MCMI/event	Financial $M/event	Indirect Safety $M/event	Electric Reliability $M/event	Financial $M/event	Indirect Safety $M	Electric Reliability	Financial	Indirect Safety EF/yr	Electric Reliability MCMI/yr	Financial $M/yr	Indirect Safety	Electric Reliability	Financial	Indirect Safety	Electric Reliability	Financial
Loss of load for all PG&E customers / Not Associated with Cyber Attack	284,683 | 99.2% | 98.6%	0.0066	75	12,347	449	1,139	39,139	449	7,744	275,792	1,147	0.5	81	3.0	8	258	2.96	51	1,818	7.56
Loss of load for all PG&E customers / Associated with Cyber Attack	481,787 | 0.8% | 1.4%	0.00005	124	20,404	449	1,883	64,679	449	13,299	467,342	1,147	0.01	1.10	0.02	0.10	3.49	0.02	0.72	25	0.06
Aggregated	286,283 | 100% | 100%	0.0066	75	12,412	449	1,145	39,347	449	7,789	277,347	1,147	0.5	83	3.0	8	262	2.99	52	1,844	7.62

C. 2023-2026 Control and Mitigation Plan

PG&E maintains seven control programs to help avoid a cascading blackout and restore service to the grid. While there are currently not any mitigations in place, PG&E continues to assess and evaluate opportunities that may be impactful to this risk.

1. Controls

- **BLKOT-C001 – Hydroelectric Blackstart Resources**: Blackstart resources can startup and deliver power without dependance on any external electric source. PG&E maintains Blackstart resources to reduce the consequences of a BLKOT event, as they are crucial to system recovery. Maintenance of these resources is done in agreement with the CAISO.

  Previous assessments of this risk noted that in the event of a BLKOT event, the hydroelectric Blackstart resources assets resulted in complete system restoration of customers in three to five days. To ensure diversity of recovery options following a BLKOT event, PG&E has three independent systems along three major rivers in Northern California: Kings River, Feather River, and Pit River.
- **BLKOT-C002 – Bay Area Blackstart Resources**: In 2017, PG&E sought to procure additional resources to reduce restoration times to customers within the San Francisco Bay Area. Two additional Blackstart capable resources were successful bidders in the Bay Area in December 2017 through the CAISO Blackstart and System Restoration Phase 2 Initiative. These units are now incorporated within PG&E's emergency restoration procedures and are estimated to reduce overall customer restoration times by up to 50 percent, though they are not managed directly by PG&E. These resources do not rely on hydroelectric power, while also allowing PG&E to diversify its Blackstart resource power sources. In conjunction with hydroelectric Blackstart Resources, PG&E has estimated that system restoration can occur over the course of two to three days.
- **BLKOT-C003 – PG&E Load Curtailment**: PG&E's Electric Emergency Plan (EEP) is an organized approach to implement CAISO load

reduction orders in a safe and responsive fashion to preserve the overall reliability of the system. When the CAISO determines there are inadequate reserves to meet the WECC Standards, it will initiate actions to address the deficiency in available system resources, including ordering PG&E to curtail load via voluntary and involuntary load reductions. The CAISO may also order these load reductions for other supply system deficiencies, such as transmission path overloads, loss of major facilities, or other unplanned or unforeseen events, that compromise the reliability of the transmission supply system.

The EEP makes a good faith effort to be equitable in impact to all customers. This is accomplished by applying the CPUC's customer prioritization orders in a reasonable and consistent fashion across the PG&E system. It is also accomplished by providing for a rotation of outages across the system so that no one area or group of customers is overburdened with outages. The EEP also emphasizes internal and external communications so that customers and emergency organizations are informed (to the degree possible) of the impending system problems and are advised of when/where the rotating outages will occur.

- **BLKOT-C004 – Redundant Grid Control Center**: PG&E has two control rooms that ensure seamless monitoring and control of the PG&E transmission grid. Both control centers are completely independent and redundant in all functionalities. The Vacaville Grid Control Center and Rocklin Grid Control Center run in parallel to ensure that the transition from one facility to the other will be seamless. Primary functions are performed at one location, with routine transfers performed to ensure smooth transition of control. This enables redundancy and flexibility for natural disasters, as well as for potential communication issues with main control room. Similarly, in the event of a physical or cyber incident, transfer of control will also be initiated.
- **BLKOT-C005 – Underfrequency Load Shedding (UFLS) and Remedial Action Schemes (RAS)**: PG&E maintains its underfrequency relays in accordance with the WECC Off-Nominal Frequency Load Shedding Plan. WECC manages a coordinated plan

for UFLS to minimize risk of total Western Interconnection system collapse and to protect generating equipment and transmission facilities against damage. The overall goal is to improve system reliability against frequency decline, which serves as a backup when all manual control mechanisms have not succeeded. RASs are designed to mitigate a variety of thermal, voltage, and stability concerns identified through power system studies. PG&E has a multitude of the different types of RASs that monitor and provide automated responses across the system. The most complex schemes focus on overall WECC stability and include generation and load shed actions.

- **BLKOT-C006 – CAISO and PG&E Coordinated Functional Registration Agreement**: Operational control of the PG&E transmission grid is shared between CAISO and PG&E to provide complete coverage of all reliability tasks and provide overlapping situational awareness. Overall, CAISO serves as the balancing authority and transmission operator, while PG&E executes switching actions and monitoring in parallel. Both entities monitor the PG&E transmission grid for reliability. If either CAISO or PG&E identifies a potential issue, they coordinate to manage required mitigations.
- **BLKOT-C007 – Operations Personnel Training**: This program focuses on training to improve personnel skillsets for situational awareness and for safe operation during routine and unexpected situations. All Operations personnel maintain NERC certification and are empowered with the authority to act in various situations. System restoration drills are performed at least on an annual basis, simulating a systemwide black out and the response work to safety restore power. These exercises emphasize communication and knowledge sharing, as well as validation of system restoration guidelines.

2. Mitigations

Currently, there is one mitigation identified for the BLKOT risk.

- **BLKOT-M001 – Site Hardening**: Based on the security improvements identified through site surveys from PG&E's Corporate Security team, PG&E continues to invest in site hardening activities at different substation sites.

3. Foundational Activities

As discussed in Exhibit (PG&E-2), Chapter 2, foundational activities are programs that enable two or more control or mitigation programs but do not directly reduce the consequences or the likelihood of risk events. There are no foundational activities identified for this risk.

D. 2027-2030 Proposed Control and Mitigation Plan

1. Changes to Controls

At this time, there are no plans to change the controls for this risk into 2027 and 2030.

2. Changes to Mitigations

PG&E plans to continue its mitigation identified for this risk, and there are no expected changes from 2027 through 2030.

E. Alternative Mitigations Analysis

PG&E considered alternative mitigations that could be deployed at a future date. Within this section, PG&E describes each of the alternative mitigations considered below.

1. Alternative Plan 1: BLKOT-A001 – Additional Site Hardening

The DVE driver demonstrates PG&E's risk to BLKOT due to susceptibility to a well-coordinated attack. PG&E had previously been attacked at the Metcalf distribution substation, which was eventually suspected to be an act of sabotage. While an attack on a distribution substation cannot lead to a cascading blackout, the incident demonstrated the vulnerability of PG&E's transmission assets.

From that event and the recent uptick of attacks on other utilities, PG&E has conducted site surveys around the Metcalf Substation and identified security improvements that can be adapted to other critical transmission substations. Additional site hardening can be incorporated at an accelerated pace across critical substations.

2. Alternative Plan 2: BLKOT-A002 – Additional Situational Awareness for Operations Personnel

One of PG&E's key controls to prevent and respond to a transmission systemwide black out revolves around Operations personnel. Expanding capabilities of personnel enables greater visibility into operations and provides a mechanism to identify hazards before they become incidents. This is important for transmission emergency restoration. To improve situational awareness, the following options were considered:

a) Implement enhanced Operational Tools to strengthen existing processes.

b) Increase Operational Support Personnel to ensure continued 24/7/365 readiness in the control center, as transmission grid continues to evolve with progressing electrification.

PACIFIC GAS AND ELECTRIC COMPANY

RISK ASSESSMENT AND MITIGATION PHASE

CHAPTER 3

RISK ASSESSMENT AND MITIGATION STRATEGY: PUBLIC CONTACT WITH INTACT ENERGIZED ELECTRICAL EQUIPMENT

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RISK ASSESSMENT AND MITIGATION STRATEGY: PUBLIC CONTACT WITH INTACT ENERGIZED ELECTRICAL EQUIPMENT

A. Executive Summary

Public Contact with Intact Energized Electrical Equipment (PCEEE) risk is defined as the risk of a reportable serious injury or a fatality to a third-party contractor or member of the public from an interaction with intact Pacific Gas and Electric Company (PG&E) energized electric assets that did not originate from asset failure. Third-party refers to a member of the public who is a non-PG&E employee and is not a PG&E contractor, whereas a serious injury is defined in alignment with the CPUC definition of a Public serious injury or fatality (SIF).[1] PCEEE has the third-highest 2027 Test Year (TY) Baseline Safety Risk Score ($60.1 million) and the fifteenth-highest 2027 TY Baseline Total Risk Score ($60.1 million) of PG&E's 32 Corporate Risk Register risks.

The drivers for the PCEEE risk include third-party working activities, third-party tree cutting services, non-working activity (e.g., a leisure activity or do-it-yourself (DIY) activity by a resident or a member of the public), aircraft contact, and third-party dig-into PG&E electrical assets. This risk also involves a cross-cutting risk of Physical Attack that largely consists of vandalism and theft/attempted theft of PG&E assets.

Exposure to this risk is measured within the PG&E service territory and spans approximately 125,600 miles of Transmission and Distribution voltage conductor and 997 substations. It is divided into four tranches to facilitate the quantitative risk analysis: Contact with Electric Distribution Overhead Assets; Contact with Electric Transmission Assets; Contact with Electric Distribution Underground Assets; and Contact with Electric Substation Assets. The risk model includes approximately 6.6 risk events each year. The risk outcome

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[1] A fatality or personal injury requiring in-patient hospitalization involving utility facilities or equipment. Equipment includes utility vehicles used during the course of business. See Decision (D.)19-04-020 and D.21-11-009.

results in a Public Serious Injury/Fatality (Public SIF).[2] Consequences of the PCEEE risk include third-party serious injuries and fatalities to the members of the public.

PG&E intends to continue its ongoing control programs of Public Awareness and Locate and Mark to manage this risk. Since 2020, the implementation of these programs has seen a reduction in risk events over time. An Additional Signage mitigation program will be deployed in 2027 with a focus on communicating electrical contact warnings on PG&E poles. PG&E is also proposing alternative mitigation programs of Enhanced Powerline Safety Settings (EPSS) in non-High Fire Threat District (HFTD) and Proximity Warning Alarms that will offer another way of generating situational awareness.

1. Risk Overview

TABLE 3-1
PCEEE RISK DEFINITION, SCOPE, AND DATA SOURCES

Line No.	Risk Name	Public Contact with Intact Energized Electric Equipment
1	Definition	PCEEE is defined as the risk of reportable serious injury or fatality to a third-party contractor or member of the public from an interaction with intact PG&E electric assets that did not originate from asset failure.
2	In Scope	Reportable third-party (public) serious injuries or fatalities due to interaction with or during the use of a PG&E facility, not involving asset failure.
3	Out of Scope	Third-party reportable serious injuries or fatalities resulting from the failure of an electric asset. Third-party gas dig-in reportable injuries or fatalities are included as key drivers for Gas Operations Loss of Containment Risks. Non-preventable motor vehicle incidents involving third-party interaction are included in the Motor Vehicle Safety Incident risk. Car (hit) pole events are included as drivers in the Distribution Overhead risk.
4	Data Quantification Sources	PG&E data including third-party initiated incidents logged in the Integrated Logging Information System (ILIS), Transmission Operation Tracking & Logging tool. Public serious Incidents Reports from PG&E's Risk Master Database, and Electric Incident Reports from 2018 through 2022.

2 A fatality or personal injury requiring in-patient hospitalization involving utility facilities or equipment. Equipment includes utility vehicles used during the course of business.

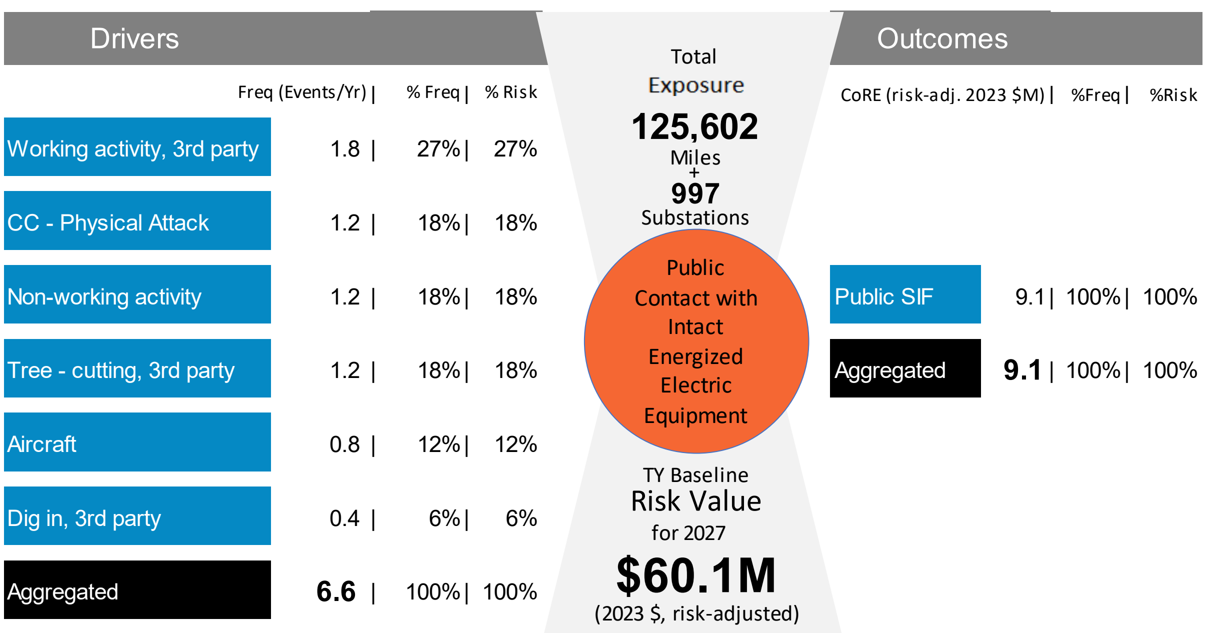
B. Risk Assessment

1. Background and Evolution

The PCEEE risk was rescoped to be presented in the 2024 RAMP; however, many components of the risk were developed out of the prior Third-Party Safety Incident risk (TPSI) presented in the 2020 RAMP.[3] Many of the risk events were previously captured in the TPSI risk as electric contact not involving asset failure, which represented a large portion of the overall PCEEE risk. Risks related to non-electric assets, for example gas-line dig ins, or events in PG&E lakes and waterways, are included in other functional area risks. To allow for a more granular focus on the key drivers that impact a significant portion of the existing TPSI risk, the PCEEE was developed to focus on the Electric incidents and drivers.

2. Risk Bow Tie

FIGURE 3-1
PCEEE RISK BOW TIE – 2027 TY



3 PG&E's 2020 Ramp Report, A.20-06-012 (June 30, 2020), Chapter 15 Risk Mitigation Plan: Third Party Safety Incident.

3. Exposure to Risk

The exposure of this risk is represented in the circuit line miles, as well as substation locations, across PG&E's 70,000 square mile service territory in northern and central California. The approximate total of PG&E's service territory is 125,000 miles, broken down by approximately 80,000 circuit miles of Distribution Overhead electric lines, 26,000 circuit miles of Distribution Underground electric lines, 18,000 circuit miles of interconnected transmission lines, and approximately 1,000 electric substations, all of which are within proximity of interaction of the public.

PG&E thus identified four tranches for the PCEEE risk, which are further described below:

- Electric Distribution Overhead Assets;
- Electric Transmission Overhead Assets;
- Electric Distribution Underground Assets; and
- Electric Substation Assets.

Electric Distribution Overhead Assets

This tranche represents approximately 80,000 circuit line miles of PG&E's electric Distribution Overhead assets. With approximately 73 percent of the overall risk, it is largely driven by the proximity to the public. The largest drivers to this tranche are associated with third-party work activities, such as crane/boom contact, third-party tree cutting activities, agricultural activities, and construction activities. Additionally, contact can occur from recreational, non-working activities from the public and aircraft contact.

Electric Transmission Overhead Assets

This tranche represents approximately 18,000 circuit line miles of PG&E's Electric Transmission Overhead assets and represents approximately 12 percent of the overall risk. The largest drivers to this tranche are associated with non-working activities and aircraft contact. Generally, non-working activities involve crane/boom contact or climbing of transmission tower structures.

Electric Distribution Underground Assets

This tranche represents approximately 26,000 circuit line miles of PG&E's electric Distribution Underground assets and represents approximately 9 percent of the overall risk. The largest driver to this tranche is associated with third-party dig-in events, whether it originates from agriculture or third-party construction diggers.

Electric Substation Assets

This tranche represents approximately 1,000 electric substations supporting PG&E's Electric Transmission and Distribution system and represents approximately 6 percent of the overall risk. This is included for completeness, as having substations within the vicinity of the public can pose a risk, although the risk is lower in comparison.

TABLE 3-2
EXPOSURE AND RISK BY TRANCHE

Line No.	Tranche Description	Percent Exposure	Safety Risk Score	Total Risk Score	Percent Risk
1	Electric Distribution Overhead Assets	64%	43.6	43.6	73%
2	Electric Transmission Overhead Assets	15%	7.3	7.3	12%
3	Electric Distribution Underground Assets	21%	5.5	5.5	9%
4	Electric Substation Assets	<1%	3.7	3.7	6%
5	Total	100%	60.1	60.1	100%

4. Drivers and Associated Frequency

PG&E identified six drivers and eight sub-drivers for the PCEEE risk. Each driver, key sub drivers, and its associated 2027 TY baseline frequency are discussed below.

D1 – Working Activity, 3rd Party: This driver refers to public contact with PG&E's energized electric overhead facilities by a third-party working for a non-PG&E contractor or under a business. This largely includes construction contractors, electricians not related to PG&E, telecommunication companies, transportation companies, and companies that operate heavy machinery (e.g., cranes, dump trucks, excavators, booms, manlifts, forklifts). Working Activity, 3rd Party accounts for 1.8 incidents per year (27 percent) of the 6.6 expected annual number of risk events. This driver is further broken into agricultural, construction, and other working activity.

D2 – Physical Attack (CCF): This driver refers to a public contact with energized electrical equipment when a 3rd party vandalizes or attempts theft associated with PG&E energized equipment. Examples include purposefully damaging or stealing copper resulting in electric contact. Physical attacks that result in a public contact with intact energized electric incidents accounted for 1.2 (18 percent) of the 6.6 expected events each year.

D3 – Non-Working Activity: This driver refers to when a member of the public comes into contact with overhead energized electrical assets in a manner where work for an established company is not involved, the member of the public is not working in a formal employer/employee relationship or in a known owner/operator business function. These categories capture accidental contact, public contact while trespassing by climbing PG&E Distribution and Transmission assets, tampering, or modifying or manipulating PG&E electrical assets in an unauthorized manner (i.e., stealing electricity), trespassing into an underground vault, recreational activities, or accidental contact in a non-working capacity or recreational pursuit. Non-working public contact with intact energized electrical incidents accounted for 1.2 (18 percent) of the 6.6 expected events each year.

D4 – Tree-Cutting, 3rd Party: This driver refers to PCEEE by a third-party working in a vegetation management capacity as a non-PG&E contractor or under a business (either owner/operator or as a business with employees). This driver does not apply to property owners and individuals engaging in "DIY" maintenance projects. 3rd party tree-cutting events accounted for 1.2 (18 percent) of the 6.6 expected annual number of risk events.

D5 – Aircraft: This driver refers to a public contact with energized electrical equipment when operating registered aircraft with the United States Federal Aviation Administration. This driver does not include operating or retrieving recreational drones, remote operated aerial devices (radio-controlled model planes, commercially operated drones), hot air balloons, wingsuits, hang-gliders, paragliders, parachutists, flying bikes, light-sport aircraft, ultralights, or amateur built aircraft which would be included in non-working activity. Aircraft that contact intact energized electrical assets accounted for 0.8 (12 percent) of the 6.6 expected events each year.

D6 – Dig In, 3rd Party: This driver refers to PCEEE with PG&E underground assets. This driver includes both working and non-working activities and can involve third-party contractors or members of the public. Dig ins that result in public contact with intact energized electrical incidents accounted for 0.4 (6 percent) of the 6.6 expected events each year.

5. Cross-Cutting Factors

A cross-cutting factor is a driver, component of a driver, or a consequence multiplier that impacts multiple risks. PG&E is presenting seven cross-cutting factors in the 2024 RAMP. Cross-cutting factors that impact the PCEEE risk event are shown in Table 3-3 below. Physical Attack is the only cross-cutting factor that has been quantified as a distinct driver for this risk. This includes incidents where a member of the public has the intent to come in contact with PG&E assets to commit a crime and ends up severely injuring themselves. Examples of this would include purposely vandalizing electrical equipment or stealing metal (e.g., copper). There are no cross-cutting factor consequences that directly impact the PCEEE risk. A description of the cross-cutting factors and the mitigations and controls that PG&E is proposing to mitigate the cross-cutting factors is in Exhibit (PG&E-2), Chapter 3.

TABLE 3-3
CROSS-CUTTING FACTOR SUMMARY

Line No.	Cross-Cutting Factor	Impacts Likelihood	Impacts Consequence
1	Climate Change	No	No
2	Cyber Attack	No	No
3	Emergency Preparedness and Response	No	No
4	IT Asset Failure	No	No
5	Physical Attack	Yes	No
6	Records and Information Management (RIM)	Yes*	No
7	Seismic	No	No

Yes The cross-cutting factor has been quantified in the model.

Yes* The cross-cutting factor does influence the baseline risk but has not been quantified in the model, or the cross-cutting factor may influence the baseline risk but further study is needed.

No The cross-cutting factor does not meaningfully influence the baseline risk.

a. Physical Attack

Vandalism and theft/attempted theft can potentially lead to contact with intact energized electrical equipment and is included as a risk driver for the PCEEE risk.

6. Consequences

The outcome of Public Contact with Energized Electrical Equipment is a CPUC reportable Public Serious Injury or Fatality (SIF). A Public SIF is defined as a fatality or personal injury requiring in-patient hospitalization for other than medical observations. The basis for measuring the consequences of the PCEEE risk is if a member of the public comes in contact with an intact energized electrical equipment (asset), resulting in a reportable serious injury or fatality.

The consequences of a third-party incident risk event occurring are:

- **Safety:** PCEEE resulting in a Serious Injury or Fatality;
- **Reliability:** This consequence is not scoped within this risk; any reliability impact would be captured in its associated asset failure risk such as Failure of Distribution Overhead Asset or Failure of Distribution Underground Asset, under the Third-Party driver; and
- **Financial:** This consequence is not scoped within this risk; any financial impact would be captured in its associated asset failure risk such as Failure of Distribution Overhead Asset or Failure of Distribution Underground, under the Third Party driver.

Incidents Reports from 2018 through 2022 were used to quantify the safety consequences of the PCEEE risk with recent trends. The PG&E Serious Incidents Report includes serious injuries and fatalities related to third-party events and Electric Incident Reports are detailed investigations made available for the CPUC to review.

The consequences of the risk event are shown in Table 3-4 below.

TABLE 3-4
RISK EVENT CONSEQUENCES

	CoRE | %Freq | %Risk	Freq	Natural Units Per Event	Expected Loss per Year (2023 $M)	Attribute Risk Score (risk-adjusted 2023 $M)
			Safety EF/event	Safety $M/yr	Safety
Public SIF	9.14 | 100% | 100%	6.6	0.5760	57.68	60.07
Aggregated	9.14 | 100% | 100%	6.6	0.5760	57.68	60.07

C. 2023-2026 Control and Mitigation Plan

The controls and mitigations proposed in the 2024 Risk Assessment and Mitigation Phase for the PCEEE risk focus upon marking electrical assets in addition to education and awareness.

1. Controls

PCEEE-C001 – Locate and Mark –- Distribution:

The L&M Program provides the physical location of PG&E's underground (UG) assets (gas and electric) for PG&E crews, contractors, along with third parties who plan to excavate near those assets. This program helps minimize the potential for a dig in to come in contact with a PG&E facility, specifically an electric UG facility for this risk.

PCEEE-C002 – Public Safety Awareness:

PG&E's Public Safety Awareness Program leverages different communication vehicles to provide educational outreach activities for third parties that may or may not be customers of PG&E but operate their business in PG&E territory. Communications may include mailers, e-mails, and educational material distribution on safe practices around PG&E assets through proper operation of equipment and excavation practices. The program support includes (but is not limited to) the following areas:

- Third-Party Contractor and Agriculture – This group includes third-party contractors, construction, agriculture, and excavation companies;
- Tree and Orchard Workers – This group focuses on distributing outreach with over 67,000 mailers to third-party vegetation management companies;

- Emergency Preparedness Support Services – This area educates first responders on public safety around utility assets. As emergency support services are the first responders to public safety incidents, educational materials on safety around utility assets help maintain safety for the public; and
- School Public Safety Education – This effort focuses on distributing outreach to over 30,000 mailers towards educators and students in the service territory. This involves a package of classroom materials tailored to increase awareness of utility issues and change behaviors of teachers, students, and student families in the service territory.

Social media and bill insert campaigns educate PG&E customers and the public about power line safety and the hazards associated with energized electrical assets. These programs are intended to reduce the number of third-party electrical contacts, focused on the residential population.

2. Mitigations

There are no direct mitigations planned during the 2023-2026 timeframe. However, there are mitigations associated with other electric risks that have secondary benefits to Public Contact with Energized Electric Equipment.

PCEEE-M002: System Hardening [Overhead]:

This mitigation hardens current circuits through the replacement of bare overhead primary conductor and other existing overhead distribution assets with equipment that increases system resiliency. This program is primarily targeted to address wildfire risk but also potentially provides some risk reduction for the PCEEE risk using covered conductor. By replacing existing bare conductor with covered conductor, the conductor is now insulated and can reduce the risk exposure of public contact.

PCEEE-M003: System Hardening [Underground]:

This mitigation converts overhead distribution lines and equipment to underground equipment. This program is primarily targeted to address wildfire risk but also provides risk reduction for the Public Contact with Energized Electric Equipment risk by removing bare conductor and placing it underground.

TABLE 3-5
PLANNED MITIGATIONS 2024-2026

Line No.	Mitigation ID[(a)]	Mitigation Name	Planned Units of Work: Unit of Measurement[(b)]	2024	2025	2026	Total
1	DOVHD-M002, WLDFR-M002, PCEEE-M002	System Hardening (Overhead)[(b)]	Miles	60	200	348	608
2	DOVHD-M022, WLDFR-M022, PCEEE-M003	System Hardening (Underground)[(b)]	UG Miles	210	310	430	950

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

(b) The units of work are presented as used in the RAMP model because the model requires that units of work are standardized. These may differ in some instances from "rate case" units – the units referred to in PG&E's GRC or other proceedings.

For additional details see Exhibit (PG&E-4), WP EO-PCEEE-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

TABLE 3-6
MITIGATION COST ESTIMATES
2024-2026 CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Mitigation ID[(a)]	Mitigation Name	2024	2025	2026	Total
1	DOVHD-M002, WLDFR-M002, PCEEE-M002	System Hardening [Overhead]	$88,585	$229,063	$368,800	$686,447
2	DOVHD-M022, WLDFR-M022, PCEEE-M003	System Hardening [Underground]	832,192	1,167,576	1,395,652	3,395,420
3		Total	$920,777	$1,396,639	$1,764,451	$4,081,868

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

For additional details see Exhibit (PG&E-4), WP EO-PCEEE-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

3. Foundational Activities

As discussed in Exhibit (PG&E-2), Chapter 2, foundational activities are programs that enable two or more control or mitigation programs but do not directly reduce the consequences or the likelihood of risk events. Table 3-7 lists foundational activities that meet this definition and includes

(1) information on the control or mitigation programs enabled and (2) the foundational activity program costs on a Net Present Value (NPV) basis that are included in CBR calculations for enabled control or mitigation programs.

TABLE 3-7
FOUNDATIONAL ACTIVITIES

Line No.	Foundational Activity ID[(a)]	Foundational Activity Name	Foundational Activity Description	Enabled Control and Mitigation IDs[(a)]	2027-2030 Millions of Dollars (NPV)[(b)]
1	LOCDM-C025	Dig-In Reduction Team	See Exhibit (PG&E-3), Chapter 2 for a description of this program.	DUNGD-C016, LOCDM-C017, PCEEE-C001	$8.36
2	LOCDM-C013	Training, Gas Qualifications	See Exhibit (PG&E-3), Chapter 2 for a description of this program.	DUNGD-C016, LOCDM-C017, PCEEE-C001	$2.92
		Total			$11.28

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

(b) NPV uses a base year of 2023.

For additional details see Exhibit (PG&E-4), WP EO-PCEEE-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

D. 2027-2030 Proposed Control and Mitigation Plan

1. Changes to Controls

PG&E plans to continue implementing the 2023-2026 controls described above in 2027-2030. The Public Safety Awareness Program is expected to shift towards digital forms of media in addition to physical mailer and bill inserts.

2. Changes to Mitigations

PG&E continues to evaluate the mitigations that could be deployed to address the PCEEE risk.

PCEEE-M001: Additional Signage: This mitigation proposes adding additional signage, pole wraps, or stickers on PG&E poles that would notify the public about the risk above (overhead assets) and below (underground facilities) associated with electrical contact. This messaging would be consistent with the PG&E "mind the lines" campaign and would be situated closer to "eye-level." This mitigation addresses the fact that mandated signage on PG&E overhead electrical assets (such as High Voltage signs mounted on wood poles) is not at "eye-level" and may not be visible to a person on the ground.

TABLE 3-8
CONTROLS COST ESTIMATES, RISK REDUCTION AND CBR
2027-2030

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[b]			
Line No.	Control ID[a]	Control Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[c] [C]/([A]+[B])
1	DUNGD-C016, PCEEE-C001, LOCDM-C017	Locate and Mark - Distribution	$85,971	$84,252	$82,567	$80,916	$231.1	$8.5	$113.3	0.5
2	DUNGD-C017, DOVHD-C024, PCEEE-C002	Public Safety Awareness Program	1,588	1,588	1,588	1,588	4.4	-	33.6	7.6
3		Total	$87,560	$85,840	$84,155	$82,504				

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.
(b) NPV uses a base year of 2023.
(c) CBR calculations include allocated Foundational Activity program costs.
For additional details see Exhibit (PG&E-4), WP EO-PCEEE-F.
The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

TABLE 3-9
PLANNED MITIGATIONS 2027-2030

Line No.	Mitigation ID [(a)]	Mitigation Name	Unit of Measurement[(b)]	Planned Units of Work 2027	2028	2029	2030	Total
1	PCEEE-M001	Additional Signage	# of Poles	575,000	575,000	575,000	575,000	2,300,000
2	DOVHD-M002, WLDFR-M002, PCEEE-M002	System Hardening [Overhead]	Miles	90	90	90	91	360
3	DOVHD-M022, WLDFR-M022, PCEEE-M003	System Hardening [Underground]	UG Miles	329	395	461	526	1,711

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

(b) The units of work are presented as used in the RAMP model because the model requires that units of work are standardized. These may differ in some instances from “rate case” units – the units referred to in PG&E’s GRC or other proceedings.

For additional details see Exhibit (PG&E-4), WP EO-PCEEE-F.

TABLE 3-10
MITIGATION COST ESTIMATES, RISK REDUCTION, CBR AND FACTORS AFFECTING SELECTION
2027-2030 EXPENSE

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[b]			
Line No.	Mitigation ID[a]	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[c] [C]/([A]+[B])
1	PCEEE-M001	Additional Signage	$1,150	$1,150	$1,150	$1,150	$3.18	–	$3.14	1.0
2		Total	$1,150	$1,150	$1,150	$1,150	–	–	–	–

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

(b) NPV uses a base year of 2023.

(c) CBR calculations include allocated Foundational Activity program costs.

For additional details see Exhibit (PG&E-4), WP EO-PCEEE-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

TABLE 3-11
MITIGATION COST ESTIMATES, RISK REDUCTION, CBR AND FACTORS AFFECTING SELECTION
2027-2030 CAPITAL

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[b]			
Line No.	Mitigation ID[a]	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[c] [C]/([A]+[B])
1	DOVHD-M002, WLDFR-M002, PCEEE-M002	System Hardening [Overhead]	$112,118	$115,481	$118,946	$122,514	$449.3	–	$7,986.9	17.8
2	DOVHD-M022, WLDFR-M022, PCEEE-M003	System Hardening [Underground]	1,320,501	1,575,164	1,852,955	2,139,167	6,482.6[d]	–	51,323.2	7.9
3		Total	$1,432,619	$1,690,645	$1,971,901	$2,261,681				

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.
(b) NPV uses a base year of 2023.
(c) CBR calculations include allocated Foundational Activity program costs.
(d) NPV of Program Cost includes a NPV of very rough estimates of OpEx savings (as a negative value) to consider potential lifetime OpEx savings in the CBR calculation.

For additional details see Exhibit (PG&E-4), WP EO-PCEEE-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

E. Alternative Mitigations Analysis

In addition to the proposed mitigations described in Section D above, PG&E considered alternative mitigations as well. The Alternative Plans consist of a combination of some or all of the proposed mitigations along with the alternative mitigation(s). PG&E describes each of the alternative mitigations it considered below and then provides a table showing the forecast costs, CBRs, and risk reduction scores for each of the Alternative Plans.

1. Alternative Plan 1: PCEEE-A001 – EPSS non-HFTD

This alternative proposal considers the application of EPSS Enablement in non-HFTD areas. PG&E has already installed EPSS devices throughout the HFTDs that are actively using sensitivity setting to trip the flow of electricity in a distribution overhead (OH) segment and mitigate an ignition at the cost of reliability. The EPSS devices could be enabled to work year-round in non-HFTD and HFTD regions to shorten the amount of time that a member of the public or a third party is exposed to a live electric current by tripping the current in the OH lines.

This mitigation would not reduce the frequency of events but could decrease the extent of injuries and minimize fatalities by faster tripping of fault currents and length of duration to contact with energized facilities. This alternative was not selected due to the low CBR when factoring in only financial costs.

TABLE 3-12
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[(a)]		
Line No.	Mitigation ID	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	PCEEE-A001	EPSS non-HFTD	$106,435	$106,499	$106,565	$106,632	$481.4	$99.6	0.2
2		Total	$106,435	$106,499	$106,565	$106,632			

(a) NPV uses a base year of 2023.

For additional details see Exhibit (PG&E-4), WP EO-PCEEE-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

2. Alternative Plan 2: PCEEE-A002 – Proximity Warning Alarms

This program considers adding proximity warning alarms to third-party cranes and boom operators. Given the incidents involving crane and boom contact with overhead energized lines, supplying high voltage proximity warning alarms to be installed onto operating equipment can pre-emptively warn operators on the potential hazards around energized lines. An initial pilot would focus on select crane and boom rental companies as it is estimated that the clientele who rent equipment are either less experienced in working with such equipment day-to-day or generally supplies other contracting/construction companies with necessary equipment. While this program provides third parties with a new safety mechanism that benefits both PG&E and the third party, the utilization of such technologies is still discretionary and without a mechanism to ensure implementation, validation of effectiveness would be an obstacle.

TABLE 3-13
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[a]		
Line No.	Mitigation ID	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	PCEEE-A002	Proximity Warning Alarms	$10,000	$10,000	$10,000	$10,000	$27.6	$79.0	2.9
2		Total	$10,000	$10,000	$10,000	$10,000			

(a) NPV uses a base year of 2023.

For additional details see Exhibit (PG&E-4), WP EO-PCEEE-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3

PACIFIC GAS AND ELECTRIC COMPANY

RISK ASSESSMENT AND MITIGATION PHASE

CHAPTER 4

RISK ASSESSMENT AND MITIGATION STRATEGY:

FAILURE OF ELECTRIC DISTRIBUTION OVERHEAD ASSETS

PACIFIC GAS AND ELECTRIC COMPANY
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RISK ASSESSMENT AND MITIGATION STRATEGY: FAILURE OF ELECTRIC DISTRIBUTION OVERHEAD ASSETS

A. Executive Summary

The Failure of Electric Distribution Overhead Assets (Failure of Electric Distribution Overhead Assets or DOVHD) chapter addresses risk events that result in a safety incident or the inability to serve power to customers due to a failure of the distribution system, as a result of equipment failure or an external driver. Failure of Electric Distribution Overhead Assets has the fourth-highest 2027 Test Year (TY) Baseline Safety Risk Value ($54.4 million) and the second-highest 2027 TY Baseline Total Risk Value ($3.354 billion) of Pacific Gas and Electric Company's (PG&E or the Company) 32 Corporate Risk Register risks. Indirect safety contributes significantly to the safety component, which comprises ~84 percent of the overall safety value associated to DOVHD. Failure of Electric Distribution Overhead Assets risk covers all 80,815 miles of distribution primary circuits.

Vegetation-caused events are the highest contributor to the overall risk associated to Failure of Electric Distribution Overhead Assets, representing 29 percent of the overall risk. Though these events are less frequent and represent only 17.5 percent of the failure events, they tend to include more consequential outcomes, which drives the higher risk. The most frequent driver that contributes to the Failure of Electric Distribution Overhead Assets risk is equipment failure, which drives 32.5 percent of the events and 27 percent of the risk.

Consequence is primarily driven by reliability impacts. Indirect safety impacts, which are a result of reliability impacts, make up 84 percent of the safety consequence for this risk. Indirect impacts are public safety impacts that are related to long duration outages, as seen in other long duration blackout events. Over 78 percent of the customer minutes out that results in indirect safety risk (i.e., long duration outages) materializes during Major Event Days (MED). MEDs represent major storm days as defined by the Institute of Electric and Electronic Engineers (IEEE) Standard 1336. In order to address MED associated failures that drive indirect-safety impact, PG&E is prioritizing mitigation programs that build system resilience against multiple risks, like wildfire and Distribution Overhead Asset Failure. As a result, mitigation programs are primarily focused in high fire risk areas first, while non-high fire risk areas are managed by our control programs, like maintenance and inspections.

The most common outcome for this risk is asset failure with no wire down (WD), no ignition, and no Enhanced Powerline Safety Settings (EPSS), representing 67 percent of the outcomes. The high frequency of this asset failure outcome makes it the highest contributor to overall risk at 40 percent.

The next highest contributing outcome to the overall risk is asset failure with WD, no ignition, and no EPSS, contributing 30 percent of the risk, but representing only 10 percent of the outcomes. The consequence of a WD event is five times higher than a non-WD event, primarily due to the increased restoration time and potential direct safety impacts. The higher consequence of these WD events has driven the prioritization of addressing failures that can lead to these outcomes, such as pole and conductor failures.

The proposed risk mitigation strategy is to improve asset health through proactive maintenance and replacement of deteriorating assets. Proactive maintenance programs identify assets that have higher probabilities of failure due to operating conditions (e.g., overloaded transformers), known issues with asset characteristics (e.g., small gauge wire), or other known preventable conditions. Routine maintenance work is key to managing this risk and represents the highest Cost-Benefit Ratio (CBR) for control programs. Additionally, the targeted overloaded transformer replacement program provides significant risk reduction by focusing on assets that are known concerns because of their overloaded condition.

The other approach used to maintain asset health is through deployment of the inspection and maintenance programs. Inspections identify components that are more likely to fail (e.g., decayed pole, damaged conductor, etc.), while the maintenance program corrects the deficiency or replaces the asset. PG&E continues to refine its inspections criteria, utilizing information available from prior inspections cycles to inform and adjust the guidance for identifying asset conditions that result in increased probabilities of failure. In addition, PG&E

continues to adopt new technologies (e.g., aerial/drone for visual inspection, resistograph for intrusive pole inspection) to inspect assets and assess in-service conditions. The enhancement of inspection technologies, techniques, and criteria reduces the noise in the volumes of maintenance tags and focuses available resources on locations and conditions with the most potential risk reduction impact.

Alternative mitigation strategies were also considered to address this risk, focusing on developing a just-in-time replacement approach for assets. Proposed alternative mitigations include deploying sensor technology to identify the likelihood of failure more accurately for poles, transformers, and other electrical equipment. Another proposed mitigation considers developing inspection enhancements utilizing Artificial Intelligence and advanced testing to assess the likelihood of asset failures more accurately. This approach to asset management allows for resources to be more targeted towards assets with the most imminent likelihood of failure and avoids retiring otherwise healthy assets early.

1 ## 1. Risk Overview

TABLE 4-1
RISK DEFINITION, SCOPE, AND DATA SOURCES

Line No.	Risk Name	Failure of Electric Distribution Overhead Assets
1	Definition	Failure of Electric Distribution Overhead Assets or lack of remote operational functionality may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy.
2	In Scope	Failure of assets associated with PG&E's overhead (OH) electrical distribution system that include: poles and support structures; primary and secondary conductor; voltage regulating equipment; protection equipment; switching equipment; transformers; and PG&E-owned streetlights
3	Out of Scope	Consequences of any ignitions associated with the failure of the electrical distribution system assets (which are included in the scope of the Wildfire risk) Consequences associated to the increased frequency or duration of sustained outages as a result of EPSS (which are included in the EPSS risk section described in Exhibit (PG&E-4), Chapter 1) Safety consequences associated with the failure of assets due to the activities of PG&E employees, PG&E contractors, and third parties (which are included in the scope of the Employee Safety Incident, Contractor Safety Incident, Public Contact with Intact Energized Electrical Equipment (PCEEE) and Motor Vehicle Incident risks)
4	Data Quantification Sources[a]	Data associated with the drivers/source of failures and data associated with reliability impact of failures are taken from PG&E's Distribution Overhead (DOH) Outage Dataset from January 1, 2017 to December 31, 2022.[b] Data associated with the safety consequences of failures is taken from PG&E's Electric Incident Reports from January 1, 2015 to December 31, 2022. Safety consequence is based on Electric Incident Reporting dataset which maintains injury/fatality incidents within PG&E service territory. Data associated with the financial impact of failures is taken from PG&E's DOH Restoration Costs Dataset from January 1, 2017 to December 31, 2020.

(a) Source documents will be provided with the workpapers (WP) on May 15, 2024.
(b) 2021 data was excluded due to the impact of the EPSS pilot.

B. Risk Assessment

1. Background and Evolution

The Failure of Electric Distribution Overhead Assets risk originated with the Conductor Failure risk identified in the 2017 Risk Assessment and Mitigation Phase (RAMP). In the 2020 RAMP, Electric Operations combined the risks associated with individual distribution OH asset types into a consolidated Failure of Electric Distribution Overhead Assets risk that included all asset types. This was part of PG&E's migration towards an event-based risk register. The consolidation supported a holistic analysis of the risk of Failure of Electric Distribution Overhead Assets, as it addresses all drivers that may cause a failure event.

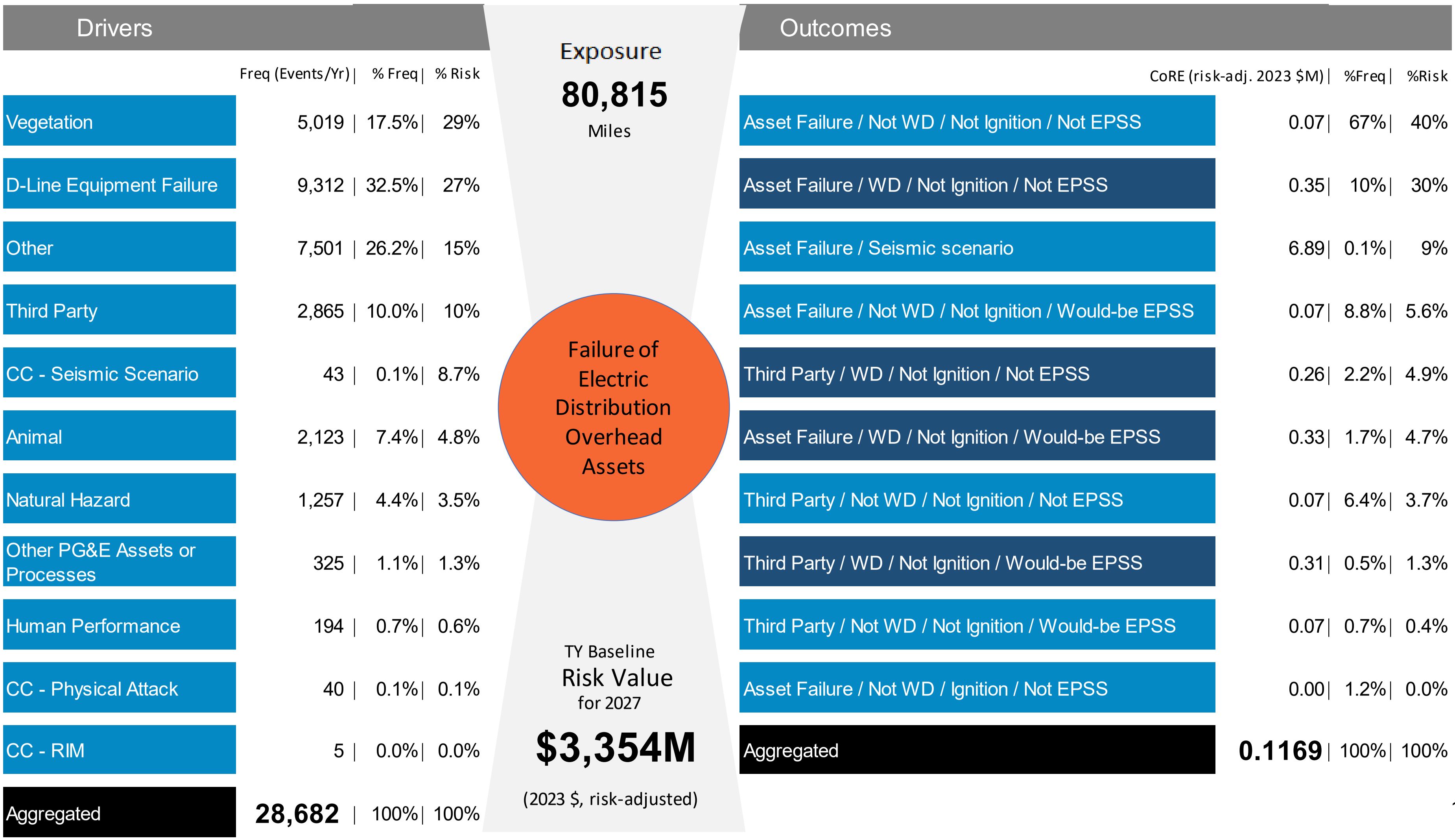
The definition of this risk in the 2024 RAMP is similar in definition to the 2020 version of the risk but the scope has been increased to include the Third-Party driver and outcomes. Outcomes have been further updated to delineate the impact of WD events and ignitions, as well as to differentiate the reliability impacts of EPSS. The increased reliability consequences of EPSS activation are not reflected in this risk, but instead are incorporated in the Wildfire with Public Safety Power Shutoff (PSPS) and EPSS risk.

The largest change to the assessment and management of this risk relates to the application of mitigations and controls. As part of PG&E's transition to integrated grid planning, asset health related work will be bundled with other risk reduction efforts, such as wildfire mitigation. This bundling creates operational efficiencies for the completion of the identified asset health work.

2. Risk Bow Tie

(PG&E-4)

FIGURE 4-1
RISK BOW TIE



a. Difference from 2020 Risk Bow Tie

In contrast from 2020, the main differences in the risk bow tie of the Failure of Electric Distribution Overhead Assets are: (1) inclusion of the Third-Party driver and outcomes, and (2) a more granular delineation of event consequence to capture Wires Down and EPSS. The impact of EPSS on reliability is not considered in this risk. Any reliability impacts of EPSS being enabled are accounted for in the Wildfire with PSPS and EPSS risk.

3. Exposure to Risk

PG&E's electric OH distribution system consists of approximately 80,000 circuit miles of primary conductor and associated assets including secondary and services. PG&E models its exposure to the Failure of Electric Distribution Overhead Assets risk based on the number of circuit miles of primary distribution conductor on its system. PG&E uses outages as a proxy for electric distribution OH asset failures.

4. Tranches

Since 2020, PG&E has updated the tranches of the Failure of Electric Distribution Overhead Assets risk to reflect a more detailed and granular understanding of the system. Previously, tranches were based on specific classifications of conductor that were small copper wire and corrosive regions, as well as reliability performance. Over time, PG&E has improved the granularity of its risk modelling and utilized its probability of failure models and historical outage data to create a relative scoring for reliability risk. Using this scoring, PG&E describes its tranches based off of deciles of risk. PG&E utilizes 20 tranches, which reflects the population of primary conductor miles divided into 10 deciles of risk and then separated by High Fire Threat Districts (HFTD)/High Fire Risk Areas (HFRA), which represents 32 percent of the risk or non-HFTD/HFRA, which represents 68 percent of the risk. Table 4-2 below shows the results of the reliability analysis for the 2023 baseline applied to the ten deciles when applied to HFTD/HFRA and non-HFTD/HFRA.

TABLE 4-2
TRANCHE LEVEL RISK ANALYSIS RESULTS

Tranche	Mileage	Risk Score	% Risk Score	Risk Score/Mile
Non-HFRA_Tranche_01	94	123.7	3.7%	1.32
Non-HFRA_Tranche_02	387	226.9	6.8%	0.59
Non-HFRA_Tranche_03	691	229.1	6.8%	0.33
Non-HFRA_Tranche_04	863	199.4	5.9%	0.23
Non-HFRA_Tranche_05	1,324	211.9	6.3%	0.16
Non-HFRA_Tranche_06	1,863	226.2	6.7%	0.12
Non-HFRA_Tranche_07	2,524	215.9	6.4%	0.09
Non-HFRA_Tranche_08	3,608	228.3	6.8%	0.06
Non-HFRA_Tranche_09	6,958	232.3	6.9%	0.03
Non-HFRA_Tranche_10	36,569	365.9	10.9%	0.01
HFRA_Tranche_01	77	124.9	3.7%	1.63
HFRA_Tranche_02	219	162.2	4.8%	0.74
HFRA_Tranche_03	385	137.6	4.1%	0.36
HFRA_Tranche_04	724	102.2	3.0%	0.14
HFRA_Tranche_05	873	84.2	2.5%	0.10
HFRA_Tranche_06	1,274	94.6	2.8%	0.07
HFRA_Tranche_07	1,941	111.1	3.3%	0.06
HFRA_Tranche_08	2,943	81.4	2.4%	0.03
HFRA_Tranche_09	4,848	79.7	2.4%	0.02
HFRA_Tranche_10	12,651	115.9	3.5%	0.01
Aggregated	80,815	3,353.5	100%	0.04

5. Drivers and Associated Frequency

PG&E identified 11 drivers for the Failure of Electric Distribution Overhead Assets risk. Each driver and its associated 2027 TY estimated frequency is discussed below.

- **D1 – Vegetation:** Failure events caused by trees, tree limbs, or other vegetation. The Vegetation driver accounts for 5,019 (17.5 percent) of the 28,682 annual expected number of outages. Vegetation-caused events have the highest consequence of the non-seismic related drivers and contribute the most risk at 29 percent.
- **D2 – D-Line (Distribution Line) Equipment Failure:** Failure events due to transformer, conductor, connector, cross-arm, and other electric distribution OH asset failures. These failures are primarily driven by transformer failure or conductor/connector failure. The D-Line Equipment Failure driver accounts for 9,312 (32.5 percent) of the 28,682 annual expected number of outages.

- **D3 – Other:** Failure events without known causes (e.g., patrol found nothing). The Other driver accounts for 7,501 (26.2 percent) of the 28,682 annual expected number of outages.
- **D4 – Third Party:** Failure events caused by third parties, such as the vandalism, car hit pole, and aircraft. The Third-Party driver accounts for 2,865 (10 percent) of the of the 28,682 annual expected number of outages.
- **D5 – Seismic Scenario (Cross-Cutting):** Failure events caused by seismic activity. This risk is described further in Exhibit (PG&E-2), Chapter 3 of this report. The Seismic Scenario driver accounts for 43 (< 1 percent) of the of the 28,682 annual expected number of outages. Due to the high consequence of a seismic event, this driver accounts for 8.7 percent of the overall risk.
- **D6 – Animal:** Failure events caused by animals, such as birds or squirrels. The Animal driver accounts for 2,123 (7.4 percent) of the 28,682 annual expected number of outages.
- **D7 – Natural Hazard:** Failure events caused by natural hazards, such as lightning, flood, ice or snow, and heat wave. The Natural Hazard driver accounts for 1,257 (4.4 percent) of the 28,682 annual expected number of outages.
- **D8 – Other PG&E Assets or Processes:** Failure events caused by PG&E processes (e.g., return circuit normal) or non-OH assets, such as generators or metering equipment. The Other PG&E Assets or Processes driver accounts for 325 (1.1 percent) of the 28,682 annual expected number of outages.
- **D9 – Human Performance:** Outage failure events caused by PG&E employees based on improper construction, operating error, or other actions. The Human Performance driver accounts for 194 (< 1 percent) of the 28,682 annual expected number of outages.
- **D10 – Physical Attack (Cross-Cutting):** Failure events caused by physical attack on PG&E assets. This risk is described further in Exhibit (PG&E-2), Chapter 3 of this report. This driver accounts for 40 (< 1 percent) of the 28,682 annual expected number of outages.

- **D11 – Records and Information Management (RIM) (Cross-Cutting):** Failure events caused by incorrect or incomplete records. This risk is described further in Exhibit (PG&E-2), Chapter 3 of this report. This driver accounts for 5 (< 1 percent) of the 28,682 annual expected number of outages.

6. Climate Adaptation Vulnerability Assessment Results

PG&E designed the Climate Adaptation Vulnerability Assessment (CAVA) to be consistent with the California Public Utilities Commission's Final Ruling on Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Change Adaptation (Rulemaking 18-04-019). The methodology outlined by Decision 20-08-046 requires utilities to perform an assessment of all assets, operations, and services that may be impacted by future risks from climate change, related to changes in temperatures, precipitation and flooding, sea level rise, wildfire, and drought- driven subsidence.

PG&E's CAVA addresses actual or expected climatic impacts on the electric distribution system, with a focus on the 2050 decadal time period. The CAVA assessment on PG&E's Electric Distribution Assets considered impacts to utility planning, facilities maintenance and construction, and communications, to maintain safe, reliable, affordable, and resilient operations.[1] The CAVA results consider all Electric Distribution assets, including OH assets. The CAVA climate risk findings consider generalized impacts from future climate hazards to all electric distribution assets that could have significant consequences for customers, public safety, and the environment.

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[1] PG&E's CAVA, Section 3.1.1.c Electric Distribution (to be published May 15, 2024).

TABLE 4-3
ELECTRIC DISTRIBUTION CAVA
CLIMATE RISK SCORES

Line No.	Climate Hazard	Adaptive Capacity	Climate Change Risk
1	Temperature	Moderate	High
2	Flooding/Precipitation	Moderate	Moderate
3	Sea Level Rise	Moderate	Moderate
4	Wildfire	High	High
5	Drought-driven subsidence	High	Low (off-ramped)

The adaptive capacity of PG&E's electric distribution assets to future climate hazards were a key factor in determining the Company's climate risk rankings. Adaptive capacity is defined as the ability of an asset or system to moderate or eliminate identified climate vulnerabilities, as assessed based on 2050 conditions and mitigate future impacts. This includes any aspect of design, planning, operations, monitoring, emergency response capacities, and other PG&E capabilities. PG&E's CAVA found that electric distribution's current mitigations and controls result in high adaptive capacity to address climate risks associated with wildfires and drought-driven subsidence and moderate adaptive capacity to address climate risks from flooding/precipitation, sea level rise, and extreme temperatures.

PG&E has already begun to experience more frequent heat storms when the system experiences long lasting hot weather with extremely high afternoon and exceptionally warm overnight temperatures. This is very unusual for coastal valley areas (e.g., De Anza, San Jose Divisions), where the temperature typically cools down at night. Heavy customer use of air conditioning for extended periods (resulting from the high daytime and nighttime ambient temperatures) contributes to excessive heating of transformers. Subsequent to this, the temperature district map was updated to upsize any new transformers being installed in coastal areas to accommodate longer periods of high customer energy demand for cooling homes and businesses.

7. Cross-Cutting Factors

A cross-cutting factor is a driver, component of a driver, or a consequence multiplier that impacts multiple risks. PG&E is presenting seven cross-cutting factors in the 2024 RAMP. The cross-cutting factors that impact the Failure of Electric Distribution Overhead Assets risks are shown in Table 4-4 below.

TABLE 4-4
CROSS-CUTTING FACTOR SUMMARY

Line No.	Cross-Cutting Factor	Impacts Likelihood	Impacts Consequence
1	Climate Change	Yes	No
2	Cyber Attack	Yes*	Yes*
3	Emergency Preparedness and Response	Yes*	Yes*
4	Information Technology Asset Failure	Yes*	Yes*
5	Physical Attack	Yes	No
6	RIM	Yes	Yes
7	Seismic	Yes	Yes

Yes The cross-cutting factor has been quantified in the model.

Yes* The cross-cutting factor does influence the baseline risk but has not been quantified in the model, or the cross-cutting factor may influence the baseline risk but further study is needed.

No The cross-cutting factor does not meaningfully influence the baseline risk.

A description of the cross-cutting factors, as well as the mitigations and controls that PG&E is proposing to mitigate the cross-cutting factors, is in Exhibit (PG&E-2), Chapter 3.

a. Climate Change

PG&E incorporates changing frequency over time due to climate change for Natural Hazards and D-Line Equipment Failure drivers. For two of the Natural Hazard subdrivers, Heat Wave and Fire, PG&E uses frequency escalation factors defined at the tranche level. For Heat Wave, PG&E uses days meeting or exceeding extreme heat outage thresholds at the circuit level, aggregating those data elements according to a mapping between circuits and tranches. For Fire, a similar aggregation approach is taken using decadal wildfire probabilities as the climate variable.

For four of the Natural Hazard subdrivers (Flood, Rain, Snow/Ice, and Lightning), PG&E uses escalation factors that are not differentiated by tranche; instead, they are based on climate data and studies at the service territory or state level. The Flood escalation factor is based on extreme precipitation modeling, which analyzes the number of days in a water year with five-day rainfall totals exceeding the 95th percentile. The Rain escalation factor is based on an analysis of Major Rain Event days per year due to Atmospheric River Storms. The Snow/Ice escalation factor (which shows a declining trend due to expected temperature increase) is based on analysis of days with extreme precipitation and average temperatures below freezing. Finally, the Lightning escalation factor is based on projected future lightning strike rates in California.

The escalating frequency of Equipment Failures is driven by heat events. The analysis done is similar to the analysis for the Heat Wave Natural Hazard, but the temperature threshold used to estimate the increasing frequency of heat events is lower for the Equipment Failure analysis. The Equipment Failure analysis focuses on high, but not extreme, heat leading to acute failure. Operating under chronically higher temperatures will tend to shorten the operational lifetime of assets, leading to increased rates of Equipment Failure.

b. Physical Attack

Vandalism and theft can lead to electrical outages affecting reliability and PG&E's customers. These events can occur in the form of copper theft, gunshots, or other impacts to assets and are incorporated into the bow tie under the third-party risk driver.

c. Records and Information Management

Improper construction, inaccurate records, and inaccurate locations of PG&E DOH assets affect both likelihood and consequence impacts for the DOVHD failure risk. These events can occur with information that is missing on assets in the field, degradation that is not known or tracked, or issues related to operations or circuit settings.

d. Seismic

PG&E's service territory is in an active seismic zone. As such, all PG&E assets are subject to the potential for damaging ground shaking and related ground failure that can range from minor to catastrophic. A large seismic event may lead to asset failures across a large area (affecting reliability).

resulting in WD events (affecting safety) and widespread outages (affecting reliability).

8. Consequences

The outcomes for the Failure of Electric Distribution Overhead Assets risks are categorized based on a combination of event-related outcome dimensions. These include:

- Asset Failure/Third-Party;
- WD/No WD;
- Ignition/Not Ignition; and
- Would Be EPSS/Not EPSS.

These conditions combine to create 16 unique outcomes and include one additional cross-cutting factor for Seismic events. The four outcomes associated to third-party ignition are not included in this risk and will not be discussed in this chapter. The probability of these events is based on the relative frequency of historical events that meet the identified criteria. The consequence of each of these events is based on a probability distribution fit to each outcome. The criteria are described below, and Table 4-5 contains the frequency and consequence dimensions of each outcome.

- Asset Failure/Third-Party: This outcome dimension is identified by the initiator of the outage event. If the outage is caused by or attributable to a third party interacting with PG&E's lines, it is considered a third-party outage. The direct safety impact of these third-party initiated events (if they come into contact with intact line or cause the asset failure) are considered as part of the PCEEE risk. All other outages are considered as part of the Asset Failure outcome dimension.
- WD/No WD: This outcome dimension identifies if the outcome includes a WD event. WD events tend to have higher consequence than events without a WD. Downed conductors pose a larger public safety threat than other outage types and result in longer restoration times, as repairs to the conductor are required to restore service.
- Ignition/No Ignition: This outcome dimension identifies if the outage is associated with an ignition event. If a risk event is associated with an ignition, the consequences of the ignition are included in the Wildfire with PSPS and EPSS risk. Only the financial impact associated to the

restoration and replacement of the equipment related to the asset failure is included in the ignition outcome.

- EPSS/Would Be EPSS: This outcome dimension identifies if the outage occurred during EPSS conditions. The impact of EPSS enablement on reliability and financial consequences is included in the Wildfire with PSPS and EPSS risk. The risk associated to outages during EPSS conditions when EPSS is not enabled is attributed to the Failure of Electric Distribution Overhead Assets risk.
- Asset Failure/Seismic: This outcome occurs when there is a seismic, cross-cutting event. The Seismic Scenario risk is described in Exhibit (PG&E-2), Chapter 3.

TABLE 4-5
RISK EVENT CONSEQUENCES

Line No.	Consequence Dimension	Freq.	Natural Units Per Event: Safety EF/event	Natural Units Per Event: Indirect Safety EF/event	Natural Units Per Event: Electric Reliability MCMI/event	Natural Units Per Event: Financial $M/event	Expected Loss per Year (2023 $ million): Safety $M/yr	Expected Loss per Year (2023 $ million): Indirect Safety $M/yr	Expected Loss per Year (2023 $ million): Electric Reliability $M/yr	Expected Loss per Year (2023 $ million): Financial $M/yr	Attribute Risk Score: Safety	Attribute Risk Score: Indirect Safety	Attribute Risk Score: Electric Reliability	Attribute Risk Score: Financial
1	Asset Failure/Not WD/Not Ignition/Not EPSS	19,101.9	0.00002	0.00005	0.02	0.004	4.85	13.86	1,253.92	82.51	4.85	13.86	1,253.9	82.51
2	Asset Failure/WD/Not Ignition/Not EPSS	2,892.5	0.0001	0.00040	0.11	0.004	2.50	17.48	976.42	12.49	2.50	17.48	976.4	12.49
3	Asset Failure/Seismic scenario	42.6	0.0001	0.00883	1.46	0.017	0.04	5.73	196.80	0.72	0.04	8.29	284.3	0.72
4	Asset Failure/Not WD/Not Ignition/Would-be EPSS	2,522.8	0.00002	0.00004	0.02	0.004	0.64	1.60	174.24	10.90	0.64	1.60	174.2	10.90
5	Third Party/WD/Not Ignition/Not EPSS	623.9	–	0.00012	0.08	0.004	–	1.17	161.14	2.69	–	1.17	161.1	2.69
6	Asset Failure/WD/Not Ignition Would-be EPSS	478.9	0.0001	0.00031	0.10	0.004	0.41	2.25	153.88	2.07	0.41	2.25	153.9	2.07
7	Third Party Not WD/Not Ignition/Not EPSS	1,846.3	–	0.00003	0.02	0.004	–	0.83	116.55	7.97	–	0.83	116.6	7.97
8	Third Party/WD/Not Ignition/Would-be EPSS	135.6	–	0.00020	0.10	0.004	–	0.41	41.17	0.59	–	0.41	41.2	0.59
9	Third Party/Not WD/Not Ignition Would-be EPSS	198.6	–	0.00004	0.02	0.004	–	0.11	13.03	0.86	–	0.11	13.0	0.86
10	Asset Failure/Not WD/Ignition/Not EPSS	355.8	–	–	–	0.004	–	–	–	1.54	–	–	–	1.54
11	Asset Failure/WD Ignition/Would-be EPSS	129.8	–	–	–	0.004	–	–	–	0.56	–	–	–	0.56
12	Asset Failure/D/Ignition/Not EPSS	128.3	–	–	–	0.004	–	–	–	0.55	–	–	–	0.55
13	Asset Failure Not WD/Ignition/Would-be EPSS	124.9	–	–	–	0.004	–	–	–	0.54	–	–	–	0.54
14	Third Party/WD Ignition/Not EPSS	34.2	–	–	–	0.004	–	–	–	0.15	–	–	–	0.15
15	Third Party/WD/Ignition/Would-be EPSS	24.8	–	–	–	0.004	–	–	–	0.11	–	–	–	0.11
16	Third Party Not WD/Ignition/Not EPSS	22.0	–	–	–	0.004	–	–	–	0.10	–	–	–	0.10
17	Third Party/Not WD /Ignition Would-be EPSS	19.4	–	–	–	0.004	–	–	–	–	–	–	–	0.08
18	Aggregated	28,682.4	0.00002	0.00010	0.03	0.004	8.45	43.44	3,087.15	124.35	8.45	46.00	3,174.63	124.43

C. 2023-2026 Control and Mitigation Plan

PG&E has a comprehensive list of foundational, control and mitigation programs, most of which continue from 2023-2026 through 2027-2030. Tables 4-6 and 4-7 list PG&E's control and mitigation programs from its 2020 RAMP, 2023 General Rate Case (GRC), and 2024 RAMP. In the sections following, PG&E describes the controls and mitigations in place for the 2023-2026 period and discusses changes to mitigations and/or controls during the 2027-2030 period.

TABLE 4-6
CONTROLS SUMMARY

Line No.	Control Number and Name	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2024-2026)	2024 RAMP (2027-2030)
1	C1 – Vegetation Management (VM)	X	Becomes DOVHD-C001		
2	C2 – VM – Catastrophic Event Memorandum Account	X			
3	C3 – Equipment Preventative Maintenance and Replacement –DOH	X	Becomes DOVHD-C003		
4	C4 – OH Conductor Replacement	X	Becomes DOVHD-C004		
5	C5 – Patrols and Inspections – DOH	X	Becomes DOVHD-C005		
6	C6 – OH Infrared Inspections	X	Becomes DOVHD-C006		
7	C7 – Supervisory Control and Data Acquisition	X	Becomes DOVHD-C007		
8	C8 – Annual Protection Reviews	X	Becomes DOVHD-C008		
9	C9 – Electric Distribution Line and Equipment Capacity	X			
10	C10 – Design Standards	X			
11	C11 – Pole Programs	X	Becomes DOVHD-C011		
12	C12 – Targeted Reliability Program	X	Becomes DOVHD-C012		
13	C13 – Enhanced Inspections - Distribution	X			
14	DOVHD-C001 – VM – DOH		X		
15	DOVHD-C001i – Incremental Routine VM		X		
16	DOVHD-C002 – VM – CEMA/Tree Mortality		X		

TABLE 4-6
CONTROLS SUMMARY
(CONTINUED)

Line No.	Control Number and Name	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2024-2026)	2024 RAMP (2027-2030)
17	DOVHD-C003 – Equipment Maintenance and Replacement – DOH		X	Becomes DOVHD-M034	
18	DOVHD-C004 – OH Conductor Replacement		X	Becomes DOVHD-M035	
19	DOVHD-C005 – Inspections – DOH		X	Becomes DOVHD-C005	
20	DOVHD-C006 – Infrared Inspections – DOH		X	X	X
21	DOVHD-C007 – Supervisory Control and Data Acquisitions		X		
22	DOVHD-C008 – Annual Protection Reviews		X	X	X
23	DOVHD-C09A – Overloaded Transformers Replacement		X	Becomes DOVHD-C009	
24	DOVHD-C011 – Pole Programs		X		
25	DOVHD-C012 – Targeted Reliability Programs		X	X	X
26	DOVHD-C013 – Patrols – DOH		X	X	X
27	DOVHD-C014 – Additional System Automation and Protection – FuseSaver		X		
28	DOVHD-C001 – VM Distribution – Routine Patrols			X	X
29	DOVHD-C002 – VM Distribution – Second Patrols			X	X
30	DOVHD-C005 – DOH Inspections – Ground			X	X
31	DOVHD-C007 – DOH Inspections – Aerial			X	X
32	DOVHD-C009 – Overloaded Transformers Replacement			X	X
33	DOVHD-C011 – Intrusive Wood Pole Inspection Program			X	X
34	DOVHD-C014 – Pole Replacement			X	X
35	DOVHD-C015 – Overloaded Pole Replacements			X	X
36	DOVHD-C016 – Animal Abatement [2AB,KAC]			X	X
37	DOVHD-C017 – Animal Abatement [2AC,KAD]			X	X
38	DOVHD-C018 – Pole Restoration Program			X	X
39	DOVHD-C019 – Emergency Distribution Replacements [17B]			X	X
40	DOVHD-C020 – Distribution Steady State Proactive Replacements [2AA]			X	X
41	DOVHD-C021 – Distribution Steady State Maintenance Replacements [KAA]			X	X
42	DOVHD-C022 – Distribution Steady State Maintenance Replacements [KAQ]			X	X
43	DOVHD-C023 – OneVeg Program			X	X
44	DOVHD-C024 – Public Safety Awareness			X	X

TABLE 4-7
MITIGATIONS SUMMARY

Line No.	Mitigation Number and Name	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2024-2026)	2024 RAMP (2027-2030)
1	M1 – Enhanced Vegetation Management (EVM)	X	Becomes DOVHD-M001		
2	M2 – System Hardening	X	Becomes DOVHD-M002		
3	M3 – Non-Exempt Surge Arrestor Replacement	X	Becomes DOVHD-M003		
4	M4 – Expulsion Fuse Replacement	X	Becomes DOVHD-M004		
5	M5 – Additional Asset Data Capture – Outage Information Reporting, Outage Cause, and Failure Analysis	X	Becomes DOVHD-M005		
6	M6 – Grasshopper/KPF Switch Replacement	X	Becomes DOVHD-M006		
7	M7 – Regulated Output Streetlight Replacement	X	Becomes DOVHD-M007		
8	M8 – Ceramic Post Insulator Replacement	X	Becomes DOVHD-M008		
9	M9 – Improved Distribution Risk Model	X	Becomes DOVHD-M009		
10	M10 – 3A and 4C Line Reclosure Controller Replacement	X	Becomes DOVHD-M010		
11	M11 – Remote Grid	X	Becomes DOVHD-M011		
12	DOVHD-M001 – EVM		X		
13	DOVHD-M002 – System Hardening		X	Split into DOVHD-M002 DOVHD-M022	
14	DOVHD-M003 – Non-Exempt Surge Arrestor Replacement		X	X	X
15	DOVHD-M004 – Expulsion Fuse Replacement		X	X	X
16	DOVHD-M005 – Additional Asset Data Captures		X	X	X
17	DOVHD-M006 – Grasshopper and KPF Switch Replacement		X	X	X
18	DOVHD-M007 – Regulated Output Streetlight Replacement		X		
19	DOVHD-M008 – Ceramic Post Insulator Replacement		X		
20	DOVHD-M009 – Improved Distribution Risk Model		X		

TABLE 4-7
MITIGATIONS SUMMARY
(CONTINUED)

Line No.	Mitigation Number and Name	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2024-2026)	2024 RAMP (2027-2030)
21	DOVHD-M010 – 3A and 4C Line Recloser Replacement		X	Split into DOVHD-M012 DOVHD-M013	
22	DOVHD-M011 – Remote Grid		X	X	X
23	DOVHD-M020 – EPSS		X		
24	DOVHD-M002 – System Hardening [OH]			X	X
25	DOVHD-M010 – Additional System Automation and Protection – FuseSaver			X	X
26	DOVHD-M012 – 3A and 4C Line Recloser Replacement [3A]			X	X
27	DOVHD-M013 – 3A and 4C Line Recloser Replacement [4C]			X	X
28	DOVHD-M014 – Butte County Rebuild			X	X
29	DOVHD-M022 – System Hardening [Underground]			X	X
30	DOVHD-M023 – Backlog Open Tag Reduction - Distribution (Pole Backlog)			X	X
31	DOVHD-M024 – Backlog Open Tag Reduction - Distribution (Capital) [2AA]			X	X
32	DOVHD-M025 – Backlog Open Tag Reduction – Distribution (Expense) [KAA]			X	X
33	DOVHD-M026 – Pole Programs – Replace Tree Attachments			X	X
34	DOVHD-M027 – Pole Clearing			X	X
35	DOVHD-M028 – VM Distribution – Focused Tree Inspections			X	X
36	DOVHD-M029 – VM Distribution – Operational Improvements			X	X
37	DOVHD-M030 – VM – Tree Removal			X	X
38	DOVHD-M031 – Portable Battery			X	X
39	DOVHD-M032 – Permanent Battery			X	X
40	DOVHD-M033 – RSI Battery			X	X
41	DOVHD-M034 – OH Fuse Install/Replace			X	X
42	DOVHD-M035 – OH Conductor Replacement			X	X

1. Controls

DOVHD-C001 – VM Distribution Routine Patrols: The VM Distribution Routine Patrol program identifies and remediates vegetation to align with compliance requirements and PG&E's VM standards. This work includes remediation of dead or dying trees, trees within the minimum distance requirements, trees causing strain or abrasion on secondary lines, or other abnormal field conditions. The patrols address compliance with General Order (GO) 95, Rule 35 in the non-HFTD/HFRA areas and support management of clearances to wildfire standards in the HFTD/HFRA areas.

DOVHD-C002 – VM Distribution Second Patrols: The VM Distribution Second Patrols program reinspects certain high-risk locations between annual routine inspections. The scope of the program is the same as the routine patrol, including the remediation of vegetation to compliance and PG&E standards.

DOVHD-C009 – Overloaded Transformers Replacement: The Overloaded Transformer Replacement program identifies and replaces overloaded transformers through overload reports using SmartMeter™ data, recorded high oil temperature indicators, or multiple thermal protective device operations during peak load periods. This does not include replacement of transformers identified through other processes. Overloaded transformer replacements provide more robust, up-to-standard designs for transformers. These up-to-standard designs include a larger transformer, as the minimum allowed transformer size has increased. PG&E is prioritizing transformer replacement locations based on the percent overload.

DOVHD-C014 – Pole Replacement: The distribution pole replacement program identifies poles for replacement when an existing pole is found to be degraded and deficient. Poles are identified for replacement through routine inspections, which include patrols, detailed visual inspections, aerial inspection, and intrusive inspections. Poles are identified for replacement when the degradation is discovered above ground, which includes the top of the pole (e.g., woodpecker damage), a few feet above the ground (e.g., termites) and at groundline or below ground (e.g., rot and fungus). Pole replacement includes providing more robust, up-to-standard designs for poles. These up-to-standard designs might include larger, stronger poles, or larger clearances.

DOVHD-C015 – Overloaded Pole Replacements: The distribution overloaded pole replacements program remediates poles that are identified for replacement when assessing the loading on the pole. This is done through the pole loading assessment program, routine inspections, or when assessing the pole for planned work (i.e., transformer replacement, etc.). Poles are also identified for replacement when they are mechanically overloaded and a larger pole is required to support the conductor and OH equipment. Pole replacement includes providing more robust, up-to-standard designs for poles. These up-to-standard designs might include larger, stronger poles, or larger clearances.

DOVHD-C016 – Animal Abatement [2AB, KAC]: The reactive Animal Abatement Program deploys animal mitigations to locations in response to animal-related outage or ignition to reduce the likelihood that the event will occur again. It includes capital modifications made to distribution poles, as well as expense repairs, replacements, or installations of bird guard materials. Bird guard materials include insulated jumpers, bushing covers, line covers, or perching platforms on incident and/or adjacent poles in response to bird incidents. This is intended to reduce arc-flashes related to animal contact.

This work is performed per United States Fish and Wildlife Service agreements and Utility Standard TD-2321S. Though this program is primarily deployed as a wildfire mitigation, it also provides additional risk reduction to the Failure of Electric Distribution Overhead Assets risk by reducing animal-related outages.

DOVHD-C017 – Animal Abatement [2AC, KAD]: The proactive Animal Abatement Program deploys animal mitigations to locations where there is believed to be a risk of animal contact or ignition. It includes capital modifications made to distribution poles, as well as expense repair, replacements, or installations of bird guard materials, such as insulated jumpers, bushing covers, line covers, or perching platforms, as part of the annual pole retrofit program. This is intended to reduce arc-flashes related to animal contact.

Though this program is primarily deployed as a wildfire mitigation, it also provides additional risk reduction to the Failure of Electric Distribution Overhead Assets risk by reducing animal-related outages.

DOVHD-C018 – Pole Restoration Program: The distribution pole restoration program provides life extension for existing poles by installing a steel truss at the base of the wood poles. The truss supports the base of the wood pole, which strengthens it. Poles are tagged for reinforcement through routine intrusive inspections and may be reinforced if the degradation is at or below ground level. To qualify for reinforcement, the pole must be in good health above ground to support the banding of the steel truss to the wood pole.

DOVHD-C019 – Emergency Distribution Replacements [17B]: The Emergency Distribution Replacements program repairs or replaces items that are identified as part of the inspections programs and are considered as safety hazards or potential immediate failures. Crews are expected to make the asset or safety hazard safe, or to address the maintenance tags in an accelerated timeline.

DOVHD-C020 – Distribution Steady State Proactive Replacements [2AA]: The Distribution Steady State Proactive Replacements program addresses corrective actions from foundational inspection work governed by GO 165 and performed in accordance with the Electric Distribution Preventive Maintenance Manual. This program reduces risk associated to Wildfire risk, the Failure of Electric Distribution Overhead Assets risk, and supports meeting compliance requirements.

DOVHD-C021 – Distribution Steady State Maintenance Replacements [KAA]: The Distribution Steady State Maintenance Replacements program addresses corrective actions from foundational inspection work governed by GO 165 and performed in accordance with the Electric Distribution Preventive Maintenance Manual. This program reduces risk associated to Wildfire risk, the Failure of Electric Distribution Overhead Assets risk, and supports meeting compliance requirements.

DOVHD-C022 – Distribution Steady State Maintenance Replacements [KAQ]: The Distribution Steady State Maintenance Replacements program addresses corrective actions tied to pole bridging and bonding from foundational inspection work governed by GO 165 and performed in accordance with the Electric Distribution Preventive Maintenance Manual. This program reduces risk associated to Wildfire risk, the Failure of Electric Distribution Overhead Assets risk, and supports meeting compliance requirements.

DOVHD-C024 – **Public Safety Awareness:** PG&E's Public Safety Awareness Program leverages different communication vehicles to provide educational outreach activities for third parties that may or may not be customers of PG&E but operate their business in PG&E territory. Communications may include mailers, e-mails, and educational material distribution on safe practices around PG&E assets through proper operation of equipment and excavation practices. The program support includes (but is not limited to) the following areas:

- <u>Third-Party Contractor and Agriculture</u> – This group includes third-party contractors, construction, agriculture, and excavation companies;
- <u>Tree and Orchard Workers</u> – This group focuses on distributing outreach to over 67,000 mailers towards third-party VM companies;
- <u>Emergency Preparedness Support Services</u> – This area educates first responders on public safety around utility assets. As emergency support services are the first responders to public safety incidents, educational materials on safety around utility assets help maintain safety for the public; and
- <u>School Public Safety Education</u> – This effort focuses on distributing outreach to over 30,000 mailers towards educators and students in the service territory. This involves a package of classroom materials tailored to increase awareness of utility issues and change behaviors of teachers, students, and student families in the service territory.

Social media and bill insert campaigns educate PG&E customers and the public about power line safety and the hazards associated with energized electrical assets. These programs are intended to reduce the number of third-party electrical contacts, focused on the residential population.

2. Mitigations

DOVHD-M002 – System Hardening [OH]: PG&E's System Hardening [OH] program hardens current circuits through the replacement of bare OH primary conductor and other existing OH distribution assets with equipment that increases system resiliency. This program is primarily targeted to address wildfire risk in HFTD/HFRA but also provides significant risk reduction for the Failure of Electric Distribution Overhead Assets risk. Activities that are included as part of the System Hardening [OH] Program include:

- <u>Covered Conductor</u>: Bare OH primary conductor and associated framing is replaced with conductor that is insulated with abrasion-resistant polyethylene coating.
- <u>Pole Replacement</u>: Existing poles are evaluated for strength requirements to withstand the new, heavier covered conductor and associated equipment. If the pole does not meet the new requirements, PG&E will replace it using wood, intumescent-wrapped wood, or composite poles.
- <u>Replacement of non-exempt Equipment</u>: Existing primary line equipment, such as fuses/cutouts and switches, are replaced with equipment that has been certified by the California Department of Forestry and Fire Protection as low fire risk.
- <u>Replacement of OH Distribution Line Transformers</u>: This activity upgrades transformers to those that contain "FR3" dielectric fluid as part of PG&E's current equipment standards.
- <u>Framing and Animal Protection Upgrades</u>: Crossarms are replaced with composite arms and wrapping jumpers: This activity also includes installing animal protection upgrades.
- <u>Vegetation Clearing to Enable Work</u>: This activity covers the clearing of vegetation on the ground directly beneath lines to execute hardening work or vegetation clearing done to meet regulatory requirements if there is a change to a line's profile (e.g., taller pole or wider crossarms) as a result of a hardening project.

DOVHD-M003 – Non-Exempt Surge Arrestor Replacement: The Surge Arrester Replacement program replaces existing non-exempt surge arresters with exempt surge arresters at locations with potentially deficient grounding. The exempt surge arresters have been found to have less propensity to cause a fire ignition. In addition, PG&E addresses common grounding by separating out the grounding on poles where surge arrestors and transformers are co-located and shared a single ground. This mitigation primarily addresses wildfire risk, but also provides additional reliability benefits as older fuses are replaced. This program was completed for targeted HFTD locations in 2023. This program will be bundled with other work to increase efficiencies as part of PG&E's transition to a holistic approach to asset management and asset health.

DOVHD-M004 – Expulsion Fuse Replacement: The non-exempt Fuse Replacement Program replaces existing non-exempt fuses with exempt fuses to reduce ignition risk. This is done because exempt equipment does not generate arcs and/or sparks during normal operation. This mitigation primarily addresses wildfire risk but provides additional reliability benefits as older fuses are replaced. This program is expected to be completed in 2025, when the expulsion fuses identified as part of this program will be mitigated.

DOVDH-M006 – Grasshopper and KPF Switch Replacement: The Grasshopper and KPF Switch Replacement program replaces a population of switches installed between the 1940s and 1970s that do not have adequate load break/make-up capability. These switches are unable to isolate downstream outages, resulting in customers upstream of the switch experiencing an outage when the line is cleared. By replacing these assets customers impacts are reduced, improving reliability. Additionally, there are known failure modes associated with the in-line bypass disconnect that require field personnel to de-energize the line before operating to avoid a possible flashover, posing a safety issue for field personnel.

DOVHD-M010 – Additional System Automation and Protection – FuseSaver: The Additional System Automation and Protection – FuseSaver Program replaces existing fuses on the system with FuseSavers. This program was primarily implemented to address wildfire risk associated with WD events, where a downed wire remains energized by a back feed condition.

DOVHD-M012 – 3A and 4C Line Recloser Replacement [3A]: The 3A Line Recloser Replacement program replaces older recloser controls with new microprocessor controls. Line reclosers operate as protective devices and create additional risk if they do not operate as intended. PG&E replaced all 3A and 4C reclosers that were part of this program in our Tier 2 and Tier 3 Fire Areas. This program prioritizes replacement of 3A and 4C Recloser Controls in non-HFRA based on customer reliability.

DOVHD-M013 – 3A and 4C Line Recloser Replacement [4C]: The 4C Line Recloser Replacement program replaces older recloser controls with new microprocessor controls. Line reclosers operate as protective devices and create additional risk if they do not operate as intended. PG&E replaced all 3A and 4C reclosers that were part of this program in our Tier 2 and Tier 3 Fire Areas. This program prioritizes replacement of 3A and 4C Recloser Controls in non-HFRA based on customer reliability. Starting in 2024, PG&E can now retrofit new controls to existing tanks, which has reduced the cost of the replacements as well as the time and resources required to conduct the replacement.

DOVHD-M014 – Butte County Rebuild: The Butte County Rebuild program is focused on rebuilding the utility infrastructure to serve the city of Paradise and the surrounding County, which was destroyed during the Camp Fire. Approximately 207 miles of electric lines were destroyed, and some had been burned multiple times in the previous decade. The Town of Paradise and Butte County expressed strong desire for underground utilities, and in 2019, PG&E committed to rebuilding the infrastructure affected by the fire, including undergrounding existing facilities.

In total, the program plans to construct 275 circuit miles of underground electric distribution infrastructure. The program is also constructing 44.4 miles of temporary and permanent OH hardened electric lines. As of March 15, 2024, the program has constructed 197 miles of underground electric infrastructure and 40.4 miles of hardened OH lines. This program will provide reduction to the Wildfire risk and the Failure of Electric

Distribution Overhead Assets Failure risk for Paradise and the surrounding county.

DOVHD-M022 – System Hardening [Underground]: In July 2021, PG&E announced its multi-year 10,000-mile undergrounding program in high wildfire risk areas. Since that time, continued work has put in place the processes, tools, and team needed to execute on this program. Benefits of this effort have been seen, as underground deployment has continued to increase year over year, supporting PG&E's stance that catastrophic wildfires shall stop.

Undergrounding will make PG&E's system safer and more resilient, allowing us to better serve our customers and address a rapidly changing climate. Additional benefits of undergrounding include improved reliability, reducing PSPS and EPSS outages, fewer emergency restoration activities during winter storms, and less need for VM activities. Undergrounding electric lines is part of PG&E's effort to minimize the growing wildfire risk in California.

The primary risk addressed by undergrounding is reducing ignition potential from OH electric distribution equipment and structures. This also has the additional benefit of increasing reliability by decreasing the Failure of Electric Distribution Overhead Assets risk. The Failure of Electric Distribution Overhead Assets drivers of vegetation, animal, and third-party driver are largely mitigated through the undergrounding of OH assets.

PG&E is filing its 10-year undergrounding plan as part of the Senate Bill (SB) 884 legislation. This filing will occur in the 2024-2026 timeframe. The results of this filing will impact the pace of execution for undergrounding significantly. PG&E anticipates completing additional undergrounding miles based on the results of the SB 884 filing and will increase the amount of risk reduction related to this program.

DOVHD-M023 – Backlog Open Tag Reduction – Distribution (Pole Backlog): The Backlog Open Tag Reduction – Distribution (Pole Backlog) Program is intended to address the backlog of pole maintenance tags that are currently associated to PG&E assets. Maintenance tags are generated as part of the inspections process. The program prioritizes the remediation of pole maintenance tags in the HFTD/HFRA to address both the risk associated to Wildfire and Failure of Electric Distribution Overhead Assets.

DOVHD-M024 – Backlog Open Tag Reduction – Distribution (Capital) [2AA]: The Backlog Open Tag Reduction – Distribution (Capital) Program is intended to address the backlog of capital equipment maintenance tags that are currently associated to PG&E assets. Maintenance tags are generated as part of the inspections process. The program prioritizes the remediation of capital equipment maintenance tags in the HFTD/HFRA to address both the risk associated to Wildfire and Failure of Electric Distribution Overhead Assets.

DOVHD-M025 – Backlog Open Tag Reduction – Distribution (Expense) [KAA]: The Backlog Open Tag Reduction – Distribution (Expense) program is intended to address the backlog of expense related maintenance tags that are currently associated to PG&E assets. Maintenance tags are generated as part of the inspections process. The program prioritizes the remediation of expense maintenance tags in the HFTD/HFRA to address both the risk associated to Wildfire and Failure of Electric Distribution Overhead Assets.

DOVHD-M026 – Pole Programs – Replace Tree Attachments: In some areas, PG&E has used living trees as distribution poles, depending on the surrounding environment. These trees are inspected and evaluated to determine their condition to support pole mounted equipment and safely keep conductors OH. When trees are identified as dead or dying, they are remediated by installing a new distribution pole and transferring the equipment and energized conductors from the tree to the new distribution pole, which reduces the risk of ignition.

DOVHD-M027 – Pole Clearing: The Pole Clearing Program creates an area of cleared vegetation surrounding poles that have non-exempt equipment or that are otherwise identified for inclusion in the program. This work is primarily done to address wildfire risk and to support compliance.

DOVHD-M028 – VM Distribution – Focused Tree Inspections: The Focused Tree Inspections Program targets PG&E's distribution system to identify and mitigate areas that are likely to see higher rates of tree failures (Areas of Concern) prior to upcoming wildfire and winter storm seasons. It utilizes Tree Risk Assessment Qualification—certified VM inspections to ensure the qualifications of the inspectors. The goal of the program is to address trees that have a high probability of failure to reduce vegetation-caused outages. This is a new program for 2023 that aligns with commitments developed to address Wildfire Mitigation Plan Revision Notice PGE-22-09.

DOVHD-M029 – VM Distribution – VM for Operational Mitigations: The VM Distribution – VM for Operational Mitigations program is intended to reduce customer impacts from vegetation due to the EPSS-enabled circuit protection devices. Proactive patrols and vegetation clearing is conducted on locations with higher volumes of EPSS-related outages. Reactive patrols and clearing are conducted when an EPSS outage is identified as being vegetation-related or caused.

DOVHD-M030 – VM – Tree Removal Inventory: The VM – Tree Removal Inventory program addresses and removes trees that were identified for mitigation by the EVM Program. EVM was retired at the end of 2022, but not all trees had been remediated prior to the completion of the program. The Tree Removal Inventory Program intends to mitigate the remaining volume of trees that had been identified, address all targeted trees, and complete by 2027. After completion of the trees targeted by this program, the program will be retired.

DOVHD-M031 – Portable Battery: The Portable Battery Program (PBP) provides portable backup battery solutions to Medical Baseline Customers and Self-Identified Vulnerable customers at risk of PSPS events to support resiliency during PSPS. The program provides a range of batteries from smaller (500 Watt-hour (Wh)) lightweight batteries to larger (6,000 Wh) batteries to meet the power needs of various medical devices. Larger batteries are delivered to those with higher energy needs. The PBP focuses on understanding customers' needs through conversation, discussing emergency plan preparedness, and assessing the best resiliency solution for each customer during PSPS. This program additionally addresses DOVHD risk by reducing the consequence of a primary outage, which will no longer affect the customers that have battery systems.

DOVHD-M032 – Permanent Battery: The Permanent Battery Program is a program that offers rebates to customers purchasing and interconnecting a permanent battery. The program is available to ~108,000 customers that are highly impacted by EPSS, regardless of medical baseline or income status. This program additionally addresses DOVHD risk by reducing the consequence of a primary outage, which will no longer affect the customers that have battery systems.

DOVHD-M033 – RSI Battery: The Residential Storage Initiative (RSI) Battery Program provides batteries and installation for select customers highly impacted by EPSS. The program focuses on providing support to vulnerable, low-income customers during wildfire safety outages, as well as medical baseline and California Alternate Rates for Energy (CARE) customers. As of December 2023, PG&E has provided permanent battery systems at no cost to 469 residential customers who had been frequently impacted by outages because of PG&E's EPSS Program. Eligible customers were enrolled in the CARE program or the Medical Baseline program. Customers enrolled did not already have a customer resiliency solution (such as a battery or permanently installed generator) and had experienced the most frequent safety related outages. This program additionally addresses DOVHD risk by reducing the consequence of a primary outage, which will no longer affect the customers that have battery systems.

DOVHD-M034 – OH Fuse Install/Replace: The OH Fuse Install/Replace program is a reliability improvement program primarily focused on installing new OH fuses on taps to protect the mainline within the circuit breaker protective zone. New OH fuse installation locations are typically identified through PG&E's Outage Review Team Process.

DOVHD-M035 – OH Conductor Replacement: The OH Conductor Replacement program replaces spans of conductor that have failed, or are likely to fail, based on historical events and conductor attributes. Attributes include number of splices, fault duty, and exposure to harsh environments, such as coastal salt and fog. This program will be bundled with other work to increase efficiencies as part of PG&E's transition to a holistic approach to asset management and asset health.

TABLE 4-8
PLANNED MITIGATIONS 2024-2026

Line No.	Mitigation ID[(a)]	Mitigation Name	Planned Units of Work: Unit of Measurement[(b)]	2024	2025	2026	Total
1	DOVHD-M002, PCEEE-M002, WLDFR-M002	System Hardening [Overhead]	Miles	60	200	348	608
2	DOVHD-M004, WLDFR-M004	Expulsion Fuse Replacement	Fuses	3,000	1,829	0	4,829
3	DOVHD-M006	Grasshopper and KPF Switch Replacement	Work Units	24	29	35	88
4	DOVHD-M010, WLDFR-M010	Additional System Automation and Protection - FuseSaver	Work Unit	71	0	0	71
5	DOVHD-M012	3A and 4C Line Recloser Replacement [3A]	Work Units	0	4	4	8
6	DOVHD-M013	3A and 4C Line Recloser Replacement [4C]	Work Units	39	35	35	109
7	DOVHD-M014, WLDFR-M014	Butte County Rebuild	UG Miles	40	20	10	70
8	DOVHD-M022, PCEEE-M003, WLDFR-M022	System Hardening [Underground]	UG Miles	210	310	430	950
9	DOVHD-M023, WLDFR-M023	Backlog Open Tag Reduction - Distribution (Pole Backlog)	Pole Notifications	8,473	30,436	22,121	61,030
10	DOVHD-M024, WLDFR-M024	Backlog Open Tag Reduction - Distribution (Capital) [2AA]	Capital Non-Pole Notifications	7,869	3,178	1,461	12,508
11	DOVHD-M025, WLDFR-M025	Backlog Open Tag Reduction - Distribution (Expense) [KAA]	Expense Non-Pole Notifications	43,857	40,355	41,851	126,063
12	DOVHD-M026, WLDFR-M026	Pole Programs - Replace Tree Attachments	Poles	1,130	1,356	1,399	3,884
13	DOVHD-M027, WLDFR-M027	Pole Clearing	Poles	70,000	60,000	65,000	195,000
14	DOVHD-M028, WLDFR-M028	VM Distribution - Focused Tree Inspections	Trees	1,807	1,788	1,788	5,383
15	DOVHD-M029, WLDFR-M029	VM Distribution - Operational Improvements	Trees	16,646	16,646	16,646	49,938
16	DOVHD-M030, WLDFR-M030	VM – Tree Removal	Trees	20,000	25,000	44,488	89,488
17	DOVHD-M031, WEPSS-M011, WPSPS-M003	Portable Battery	# Batteries	4,050	3,645	3,281	10,976
18	DOVHD-M032, WEPSS-M012, WPSPS-M004	Permanent Battery	# Batteries	1,000	1,000	1,000	3,000
19	DOVHD-M033, WEPSS-M013, WPSPS-M005	RSI Battery	# Batteries	1,800	1,300	1,300	4,400
20	DOVHD-M034	OH Fuses Install/Replace	Work Units	92	106	244	442
21	DOVHD-M035	OH Conductor Replacement	Work Units	0	1	3	4

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.
(b) The units of work are presented as used in the RAMP model because the model requires that units of work are standardized. These may differ in some instances from “rate case” units – the units referred to in PG&E’s GRC or other proceedings.

For additional details see Exhibit (PG&E-4), WP EO-DOVHD-F.

The estimated costs for the work planned in 2024-2026 are shown in Tables 4-9 and 4-10 below.

TABLE 4-9
MITIGATIONS COST ESTIMATES
2024-2026 EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Mitigation ID[(a)]	Mitigation Name	2024	2025	2026	Total
1	DOVHD-M025, WLDFR-M025	Backlog Open Tag Reduction – Distribution (Expense) [KAA]	$103,684	$105,174	$104,977	$313,835
2	DOVHD-M027, WLDFR-M027	Pole Clearing	28,803	27,363	25,995	82,161
3	DOVHD-M028, WLDFR-M028	VM Distribution – Focused Tree Inspections	220,069	220,291	220,629	660,989
4	DOVHD-M029, WLDFR-M029	VM Distribution – Operational Improvements	20,910	20,910	20,910	62,730
5	DOVHD-M030, WLDFR-M030	VM – Tree Removal	44,090	55,113	98,075	197,278
6	DOVHD-M031, WEPSS-M011, WPSPS-M003	Portable Battery	12,590	11,331	10,199	34,120
7	DOVHD-M032, WEPSS-M012, WPSPS-M004	Permanent Battery	5,300	5,300	5,300	15,900
8	DOVHD-M033, WEPSS-M013, WPSPS-M005	RSI Battery	32,134	23,208	23,208	78,550
9		Total	$467,580	$468,690	$509,293	$1,445,563

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

For additional details see Exhibit (PG&E-4), WP EO-DOVHD-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

TABLE 4-10
MITIGATIONS COST ESTIMATES
2024-2026 CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Mitigation ID[(a)]	Mitigation Name	2024	2025	2026	Total
1	DOVHD-M002, PCEEE-M002, WLDFR-M002	System Hardening [Overhead]	$88,585	$229,063	$368,800	$686,447
2	DOVHD-M004, WLDFR-M004	Expulsion Fuse Replacement	19,800	12,313	–	32,113
3	DOVHD-M006	Grasshopper and KPF Switch Replacement	1,176	1,199	1,223	3,599
4	DOVHD-M010, WLDFR-M010	Additional System Automation and Protection - FuseSaver	7,865	–	–	7,865
5	DOVHD-M012	3A and 4C Line Recloser Replacement [3A]	–	100	85	185
6	DOVHD-M013	3A and 4C Line Recloser Replacement [4C]	980	900	765	2,644
7	DOVHD-M014, WLDFR-M014	Butte County Rebuild	155,121	66,275	31,497	252,893
8	DOVHD-M022, PCEEE-M003, WLDFR-M022	System Hardening [Underground]	832,192	1,167,576	1,395,652	3,395,420
9	DOVHD-M023, WLDFR-M023	Backlog Open Tag Reduction - Distribution (Pole Backlog)	212,575	652,203	471,726	1,336,504
10	DOVHD-M024, WLDFR-M024	Backlog Open Tag Reduction - Distribution (Capital) [2AA]	100,145	40,149	18,458	158,752
11	DOVHD-M026, WLDFR-M026	Pole Programs - Replace Tree Attachments	30,158	30,761	26,147	87,065
12	DOVHD-M034	OH Fuses Install/Replace	1,138	1,355	2,582	5,075
13	DOVHD-M035	OH Conductor Replacement	–	141	1,320	1,461
14		Total	$1,449,736	$2,202,035	$2,318,254	$5,970,024

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

For additional details see Exhibit (PG&E-4), WP EO-DOVHD-F.

The cost estimates in this table are generally based on PG&E’s 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

3. Foundational Activities

As discussed in Exhibit (PG&E 2), Chapter 2, foundational activities are programs that enable two or more control or mitigation programs but do not directly reduce the consequences or the likelihood of risk events. Table 4-11 describes foundational activities that meet this definition and includes (1) information on the control or mitigation programs enabled and (2) the foundational activity program costs on a Net Present Value (NPV) basis that are included in CBR calculations for enabled control or mitigation programs.

DOVHD-C005 – DOH Inspections – Ground: DOH Ground inspections utilize detailed inspections, conducted from the ground, to proactively identify areas where PG&E needs to perform corrective work to alleviate imminent equipment failures that could create fire or safety risk. These include abnormal conditions on electric distribution poles, equipment, components, conductors, vegetation, and/or third-party conditions. DOH assets in HFTD/HFRA are visually inspected in accordance with GO 165 and with the criteria/guidance set forth in PG&E's EDPM and OH Job Aid (TD-2305M-JA02).

DOVHD-C006 – DOH Inspections – Infrared (IR): DOH Infrared (IR) inspections evaluate OH electric distribution lines and equipment using IR technology and cameras. These inspections can identify hot spots or conditions that may indicate potential equipment failure. Although most failure modes can be detected via visual inspections, there are some that cannot (e.g., components experiencing excessive heat condition). IR inspections help identify potentially damaged and/or faulty components that are not detectable by visual inspection methods alone.

DOVHD-C007 – DOH Inspections – Aerial: DOH Aerial inspections utilize drones, bucket trucks, or other methods to provide an aerial view of distribution system assets. Aerial inspections complement ground-based inspection methods by identifying deficiencies or failure modes (e.g., cross-arm and pole degradation) that are challenging to view or not visible from ground inspections alone.

Aerial inspections are also paired with intrusive inspections as part of PG&E's Comprehensive Pole Inspection (CPI) Program to holistically assess the condition of electric distribution assets, including those with open maintenance tags. The intrusive component of the CPI Program entails using drills to allow PG&E to assess the structural integrity of its wood electric distribution poles. The intrusive test also evaluates whether pole reinforcement would be a better alternative than pole replacement in some cases. Together, the aerial and intrusive inspections allow PG&E to determine with unprecedented accuracy the severity of conditions on its distribution assets and the necessity for maintenance. The CPI Program will help PG&E develop a tag maintenance plan that contains the conditions most urgent to address in both HFTD and non-HFTD.

DOVHD-C008 – Annual Protection Reviews: Annual protection reviews evaluate the coordination of protective devices across a subset of the distribution system to ensure that all protection requirements are met in accordance with most current standards. These reviews are performed annually and support meeting compliance requirements. The annual review process is designed to capture steady state changes to the system that might not be addressed during specific project work occurring on the distribution system.

DOVHD-C011 – Intrusive Wood Pole Inspection Program: The Intrusive Wood Pole Inspection Program, also referred to as Pole Test and Treat (PT&T), is a method to evaluate in service wood poles for early signs of deterioration. PT&T examines the internal and external condition of the pole at and below groundline, directly measuring shell thickness and examining below ground degradation. The inspection identifies wood poles that are nearing the end of their service life and recommends these poles for replacement or reinforcement, prior to failure.

DOVHD-C013 – Patrols DOH: DOH Patrols are a simple, visual examination of applicable OH facilities to identify obvious structural problems and hazards. Patrol inspections are a visual review of asset condition to proactively detect imminent, or existing, safety or reliability hazards in alignment with GO 165. DOH patrols may be executed on foot, by vehicle, or by aerial means.

DOVHD-C023 – OneVeg Program: The OneVeg program provides a single, integrated platform with map-based work execution, monitoring, and validation for all VM programs. This platform enables VM personnel to have better visibility into the vegetation work that has been prescribed or completed. This program supports operational efficiency and improved customer experience through the integrated platform.

DOVHD-M005 – Additional Asset Data Captures: This program consists of various efforts to improve PG&E's ability to capture information about the location of outages, cause of outages, and reasons for equipment failures. It includes facilitating asset data capture on mobile devices in the field or automatically, efforts to improve PG&E's outage database, and changes in standards/ procedures to expand the amount of asset failure information gathered by field personnel. These improvements support PG&E's move towards a more data-driven, risk-based asset management strategy.

TABLE 4-11
FOUNDATIONAL ACTIVITIES

Line No.	Foundational Activity ID [a]	Foundational Activity Name	Foundational Activity Description	Enabled Control and Mitigation IDs [a]	2027-2030 Millions of Dollars (NPV)[b]
1	DOVHD-C005, WLDFR-C005	Distribution Overhead Inspections - Ground	See description above	DOVHD-C014, WLDFR-C014, DOVHD-C019, WLDFR-C019, DOVHD-C020, WLDFR-C020, DOVHD-C021, WLDFR-C021, DOVHD-C022, WLDFR-C022	$20.69
2	DOVHD-C006, WLDFR-C006	Distribution Overhead Inspections - Infrared	See description above	DOVHD-C014, WLDFR-C014, DOVHD-C019, WLDFR-C019, DOVHD-C020, WLDFR-C020, DOVHD-C021, WLDFR-C021, DOVHD-C022, WLDFR-C022	3.76
3	DOVHD-C007, WLDFR-C007	Distribution Overhead Inspections - Aerial	See description above	DOVHD-C014, WLDFR-C014, DOVHD-C019, WLDFR-C019, DOVHD-C020, WLDFR-C020, DOVHD-C021, WLDFR-C021, DOVHD-C022, WLDFR-C022	145.82
4	DOVHD-C008	Annual Protection Reviews	See description above	DOVHD-C014, WLDFR-C014, DOVHD-C019, WLDFR-C019, DOVHD-C020, WLDFR-C020, DOVHD-C021, WLDFR-C021, DOVHD-C022, WLDFR-C022	28.08
5	DOVHD-C011, WLDFR-C011	Intrusive Wood Pole Inspection Program	See description above	DOVHD-C014, WLDFR-C014	124.75
6	DOVHD-C013, WLDFR-C013	Patrols - Distribution Overhead	See description above	DOVHD-C014, WLDFR-C014, DOVHD-C019, WLDFR-C019, DOVHD-C020, WLDFR-C020, DOVHD-C021, WLDFR-C021, DOVHD-C022, WLDFR-C022	16.20
7	DOVHD-C023, WLDFR-C077	OneVeg Program		WLDFR-C001, DOVHD-C001, WLDFR-C002, DOVHD-C002, WLDFR-M027, DOVHD-M027, WLDFR-M028, DOVHD-M028, WLDFR-M029, DOVHD-M029, WLDFR-M030, DOVHD-M030	69.70
8	DOVHD-M005	Additional Asset Data Captures	See description above	DOVHD-C014, WLDFR-C014, DOVHD-C019, WLDFR-C019, DOVHD-C020, WLDFR-C020, DOVHD-C021, WLDFR-C021, DOVHD-C022, WLDFR-C022	4.38
9	WLDFR-C010	Situational Awareness and Forecasting Initiatives - EFD	See description above	DOVHD-C019, WLDFR-C019, DOVHD-C020, WLDFR-C020, DOVHD-C021, WLDFR-C021, DOVHD-C022, WLDFR-C022	19.20
10	WLDFR-C012	Situational Awareness and Forecasting Initiatives - DFA	See description above	DOVHD-C019, WLDFR-C019, DOVHD-C020, WLDFR-C020, DOVHD-C021, WLDFR-C021, DOVHD-C022, WLDFR-C022	8.23
11	WLDFR-C023	Situational Awareness and Forecasting Initiatives - Line Sensors	See description above	DOVHD-C019, WLDFR-C019, DOVHD-C020, WLDFR-C020, DOVHD-C021, WLDFR-C021, DOVHD-C022, WLDFR-C022	6.75
12		Total			$447.55

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

(b) NPV uses a base year of 2023.

For additional details see Exhibit (PG&E-4), WP EO-DOVHD-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030.

See Exhibit (PG&E-1), Chapter 1, Section D.3.

D. 2027-2030 Proposed Control and Mitigation Plan

1. Changes to Controls

PG&E plans to continue implementing the 2023-2026 controls described above in 2027-2030.

2. Changes to Mitigations

PG&E intends to continue the deployment of the mitigations in the 2023-2026 period, excluding the following programs which will be discontinued:

- DOVHD-M003 – Non-Exempt Surge Arrestors. This program is expected to address the known population prior to 2027;
- DOVHD-M004 – Expulsion Fuse Replacement. This program is expected to address the known population prior to 2027;
- DOVHD-M010 – Additional System Automation and Protection – FuseSavers. Deployment of other protection devices is being explored to support EPSS; and
- DOVHD-M014 – Butte County Rebuild. This program is expected to be completed prior to 2027.

TABLE 4-12
2027-2030 CONTROLS COST ESTIMATES, RISK REDUCTION, AND CBR

			Thousands of Nominal Dollars				Millions of Dollars (NPV) [b]			
	Control ID	Control Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[c] [C]/([A]+[B])
1	DOVHD-C001, WLDFR-C001	VM Distribution - Routine Patrols	$712,688	$714,555	$716,478	$718,459	$1,978.0	$43.0	$6,531.2	3.2
2	DOVHD-C002, WLDFR-C002	VM Distribution - Second Patrols	79,793	80,125	80,466	80,817	221.9	4.8	172.4	0.8
3	DOVHD-C009, WLDFR-C009	Overloaded Transformers Replacement	8,087	8,249	8,413	8,582	32.0	-	6.2	0.2
4	DOVHD-C014, WLDFR-C014	Pole Replacement	728,990	504,588	504,588	415,709	2,098.9	263.4	2,285.0	1.0
5	DOVHD-C015, WLDFR-C015	Overloaded Pole Replacements	12,019	12,019	12,019	12,019	46.2	-	0.8	<0.1
6	DOVHD-C016, WLDFR-C016	Animal Abatement [2AB,KAC]	3,666	3,666	3,666	3,666	13.7	-	246.5	18.0
7	DOVHD-C017, WLDFR-C017	Animal Abatement [2AC,KAD]	8,869	8,869	8,869	8,869	29.6	-	3,464.6	117.1
8	DOVHD-C018, WLDFR-C018	Pole Restoration	6,429	6,557	6,688	6,822	25.4	-	19.7	0.8
9	DOVHD-C019, WLDFR-C019	Emergency Distribution Replacements [17B]	98,510	98,510	98,510	98,510	378.4	35.6	46,108.1	111.4
10	DOVHD-C020, WLDFR-C020	Distribution Steady State Proactive Replacements [2AA]	107,042	182,753	182,753	212,571	647.5	61.0	1,983.2	2.8
11	DOVHD-C021, WLDFR-C021	Distribution Steady State Maintenance Replacements [KAA]	25,217	98,372	91,252	59,648	187.3	17.6	1,750.6	8.5
12	DOVHD-C022, WLDFR-C022	Distribution Steady State Maintenance Replacements [KAQ]	859	859	859	859	2.4	0.2	0.5	0.2
13	DOVHD-C024, DUNGD-C017, PCEEE-C002	Public Safety Awareness	1,588	1,588	1,588	1,588	4.4	-	33.6	7.6
14		Total	$1,793,757	$1,720,709	$1,716,149	$1,628,119				

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

(b) NPV uses a base year of 2023.

(c) CBR calculations include allocated Foundational Activity Program cost.

For additional details see Exhibit (PG&E-4), WP EO-DOVHD-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

TABLE 4-13
PLANNED MITIGATIONS 2027-2030

Line No.	Mitigation ID [(a)]	Mitigation Name	Unit of Measurement [(b)]	Planned Units of Work 2027	2028	2029	2030	Total
1	DOVHD-M002, PCEEE-M002, WLDFR-M002	System Hardening [Overhead]	Miles	90	90	90	90	360
2	DOVHD-M006	Grasshopper and KPF Switch Replacement	Work Units	42	50	60	72	223
3	DOVHD-M012	3A and 4C Line Recloser Replacement [3A]	Work Units	4	4	4	4	16
4	DOVHD-M013	3A and 4C Line Recloser Replacement [4C]	Work Units	35	35	35	35	140
5	DOVHD-M022, PCEEE-M003, WLDFR-M022	System Hardening [Underground]	UG Miles	329	395	461	526	1,711
6	DOVHD-M023, WLDFR-M023	Backlog Open Tag Reduction - Distribution (Pole Backlog)	Pole Notifications	1,780	2,905	3,501	16,358	24,544
7	DOVHD-M024, WLDFR-M024	Backlog Open Tag Reduction - Distribution (Capital) [2AA]	Capital Non-Pole Notifications	4,482	1,559	2,009	14,991	23,041
8	DOVHD-M025, WLDFR-M025	Backlog Open Tag Reduction - Distribution (Expense) [KAA]	Expense Non-Pole Notifications	41,850	9,405	11,189	53,491	115,935
9	DOVHD-M026, WLDFR-M026	Pole Programs - Replace Tree Attachments	Poles	979	979	979	979	3,918
10	DOVHD-M027, WLDFR-M027	Pole Clearing	Poles	65,000	65,000	65,000	65,000	260,000
11	DOVHD-M028, WLDFR-M028	VM Distribution - Focused Tree Inspections	Trees	1,788	1,788	1,788	1,788	7,153
12	DOVHD-M029, WLDFR-M029	VM Distribution - Operational Improvements	Trees	16,646	16,646	16,646	16,646	66,584
13	DOVHD-M030, WLDFR-M030	VM – Tree Removal	Trees	44,488	44,488	44,488	44,488	177,953
14	DOVHD-M031, WEPSS-M011, WPSPS-M003	Portable Battery	# Batteries	2,953	2,658	2,392	2,152	10,155
15	DOVHD-M032, WEPSS-M012, WPSPS-M004	Permanent Battery	# Batteries	1,000	1,000	1,000	1,000	4,000
16	DOVHD-M033, WEPSS-M013, WPSPS-M005	RSI Battery	# Batteries	1,300	1,300	1,300	1,300	5,200
17	DOVHD-M034	OH Fuses Install/Replace	Work Units	194	298	255	271	1,019
18	DOVHD-M035	OH Conductor Replacement	Work Units	16	13	18	15	62

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

(b) he units of work are presented as used in the RAMP model because the model requires that units of work are standardized. These may differ in some instances from “rate case” units – the units referred to in PG&E’s GRC or other proceedings.

For additional details see Exhibit (PG&E-4), WP EO-DOVHD-F.

TABLE 4-14
MITIGATIONS COST ESTIMATES, RISK REDUCTION, CBR, AND FACTORS AFFECTING SELECTION
2027-2030 EXPENSE

Line No.	Mitigation ID[a]	Mitigation Name	Thousands of Nominal Dollars 2027	2028	2029	2030	Millions of Dollars (NPV)[b] Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[c] [C]/([A]+[B])	Factors Affecting Selection
1	DOVHD-M025, WLDFR-M025	Backlog Open Tag Reduction - Distribution (Expense) [KAA]	$86,450	$19,428	$23,113	$110,496	$164.0	–	$1,088.7	6.6	
2	DOVHD-M027, WLDFR-M027	Pole Clearing	24,695	23,460	22,287	21,173	63.6	1.4	147.2	2.3	
3	DOVHD-M028, WLDFR-M028	VM Distribution - Focused Tree Inspections	220,976	221,334	221,702	222,082	612.4	13.3	3,370.8	5.4	
4	DOVHD-M029, WLDFR-M029	VM Distribution - Operational Improvements	20,910	20,910	20,910	20,910	57.8	1.3	299.8	5.1	
5	DOVHD-M030, WLDFR-M030	VM – Tree Removal	98,075	98,075	98,075	98,075	271.2	5.9	1,374.3	5.0	
6	DOVHD-M031, WEPSS-M011, WPSPS-M003	Portable Battery	9,180	8,263	7,436	6,690	22.0	–	94.6	4.3	
7	DOVHD-M032, WEPSS-M012, WPSPS-M004	Permanent Battery	5,300	5,300	5,300	5,300	14.7	–	200.3	13.7	
8	DOVHD-M033, WEPSS-M013, WPSPS-M005	RSI Battery	23,208	23,208	23,208	23,208	64.2	–	260.3	4.1	
9		Total	$488,793	$419,978	$422,032	$507,934					

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.
(b) NPV uses a base year of 2023.
(c) CBR calculations include allocated Foundational Activity program costs.

For additional details see Exhibit (PG&E-4), WP EO-DOVHD-F.

The cost estimates in this table are generally based on PG&E’s 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

TABLE 4-15
MITIGATIONS COST ESTIMATES, RISK REDUCTION, CBR, AND FACTORS AFFECTING SELECTION
2027-2030 CAPITAL

Line No.	Mitigation ID [a]	Mitigation Name	Thousands of Nominal Dollars				Millions of Dollars (NPV) [b]				
1			2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR [c] [C]([A]+[B])	Factors Affecting Selection
2	DOVHD-M002, PCEEE-M002, WLDFR-M002	System Hardening [Overhead]	$112,118	$115,481	$118,946	$122,514	$449.3	–	$7,986.9	17.8	
3	DOVHD-M006	Grasshopper and KPF Switch Replacement	1,248	1,273	1,298	1,324	4.9	–	0.2	<0.1	Operational and Execution Considerations
4	DOVHD-M012	3A and 4C Line Recloser Replacement [3A]	70	70	70	70	0.3	–	0.0	<0.1	Operational and Execution Considerations
5	DOVHD-M013	3A and 4C Line Recloser Replacement [4C]	630	630	630	630	2.4	–	0.1	<0.1	Operational and Execution Considerations
6	DOVHD-M022, PCEEE-M003, WLDFR-M022	System Hardening [Underground]	1,320,501	1,575,164	1,852,955	2,139,167	6,482.6 [d]	–	51,323.2	7.9	
7	DOVHD-M023, WLDFR-M023	Backlog Open Tag Reduction - Distribution (Pole Backlog)	31,260	51,016	61,483	287,273	389.1	–	41.5	0.1	Compliance Requirement
8	DOVHD-M024, WLDFR-M024	Backlog Open Tag Reduction - Distribution (Capital) [2AA]	46,631	16,220	20,902	155,968	219.7	–	165.2	0.8	Compliance Requirement
9	DOVHD-M026, WLDFR-M026	Pole Programs - Replace Tree Attachments	18,303	18,303	18,303	18,303	126.8	–	4.5	<0.1	Modeling
10	DOVHD-M034	OH Fuses Install/Replace	1,691	2,594	2,221	2,359	8.5	–	73.3	8.7	
11	DOVHD-M035	Overhead Conductor Replacement	2,981	11,658	9,243	13,902	35.3	–	0.0	<0.1	Modeling
12		Total	$1,535,432	$1,792,409	$2,086,051	$2,741,509					

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.
(b) NPV uses a base year of 2023.
(c) CBR calculations include allocated Foundational Activity program costs.
(d) NPV of Program Cost includes a NPV of very rough estimates of OpEx savings (as a negative value) to consider potential lifetime OpEx savings in the CBR calculation.

For additional details see Exhibit (PG&E-4), WP EO-DOVHD-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

3. Factors Affecting Mitigation Selection

Mitigation and control programs have been included in the 2027-2030 risk mitigation plan for a variety of reasons beyond the efficiency of risk reduction, including compliance, operational considerations, or other factors. The programs included in the risk mitigation plan based on these criteria are described below.

a. Operational and Execution Considerations

The Overloaded Transformers Replacement program targets higher risk transformers more effectively than the average transformer failure rates in the bow tie analysis. As such, PG&E believes this modeling limitation results in this program being represented by a lower CBR than it achieves.

The Grasshopper and KPF Switch Replacement program targets replacement of specific switches that do not have adequate load break/make-up capability. Since these switches are unable to isolate downstream outages, customers upstream of the switch may experience an outage when the line is cleared. Additionally, there are known failure modes assigned with the in-line bypass disconnect that require field personnel to de-energize the line before operating to avoid a possible flashover, posing a safety issue for field personnel.

The 3A and 4C Line Recloser Controller Replacement programs replace older Recloser Controls with new microprocessor controls. By replacing this component at a lower cost instead of the whole line recloser itself, customer reliability impacts and financial cost for replacement are reduced.

b. Compliance Requirements

Backlog Open Tag Reduction – Distribution (Pole Backlog) and Backlog Open Tag Reduction – Distribution (Capital) [2AA] focus on addressing the backlog of pole maintenance tags and capital equipment maintenance tags that are currently associated to PG&E assets. Remediation of these tags address risk associated to Wildfire and the risk associated to Failure of Electric Distribution Overhead Assets. These programs are required as part of compliance with GO-95.

c. Modeling Limitations

When a tree is utilized as a tree connect, limbs on the tree need to be removed to avoid contact, which, in turn, has an impact to tree health. If the tree dies, it poses a threat as both a pole failure and a potential vegetation strike. PG&E Subject Matter Experts believe that the low CBR score generated by the risk model is due to data limitations, that is, limited data on tree attachment failures. PG&E will continue to remove electrified lines and support structures on dead or dying trees.

The Overhead Conductor Replacement program replaces conductor that is degraded, has a high volume of splices, or is otherwise identified as having characteristics that would make it more likely to fail. In modeling the consequence of an outage, the financial impact of that outage averages all the equipment replacement costs to all outages. Conductor failures require the replacement of a high cost asset as compared to other outages where equipment may not need to be replaced. The increased financial cost that is reduced by proactively replacing overhead conductor is understated due to how the financial consequence of failures is modeled.

E. Alternative Mitigations Analysis

In addition to the proposed mitigations described in Section C, PG&E also considered alternative mitigations. PG&E describes each of the alternative mitigations it considered below and then provides a table showing the cost estimates, risk reduction values, and CBRs for each of the Alternative Plans.

1. Alternative Plan 1: DOVHD-A001 – System Hardening [Underground]

PG&E has considered an alternative plan for the System Hardening [Underground] program (WLDFR-M022), which differs from the approach described in Section C.2. In the alternative proposal, PG&E considered a workplan that only mitigates Primary cable risk through Undergrounding, with Secondary and Service cable risk mitigations limited to OH Hardening. The alternative workplan would propose fewer undergrounded miles per year after 2027 (i.e., 2027: 500 miles; 2028: 550 miles; 2029: 600 miles, and 2030: 650 miles), lowering the total cost of the program, and would have a

CBR of 9.7. This would allow for additional budget to be allocated towards other electric programs, primarily addressing the backlog of identified pole tags that need work completed.

PG&E rejected this alternative for multiple reasons. Our analysis concluded that budget re-allocation to pole tag programs would not provide an incremental risk reduction benefit, and the undergrounding of Secondary and Service lines provide additional benefits that are not as easily quantified, such as improvements to PSPS, end of line reliability, and customer satisfaction.

TABLE 4-16
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION AND CBR
2027-2030

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[b]		
Line No.	Mitigation ID[a]	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [C]	CBR [C]/([A]+[B])
1	DOVHD-A001, PCEEE-A003, WLDFR-A001	System Hardening [Underground] (Alternative Workplan)	$1,459,940	$1,571,705	$1,714,569	$1,861,676	$6,261.3[c]	$60,725.9	9.7
2		Total	$1,459,940	$1,571,705	$1,714,569	$1,861,676			

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.
(b) NPV uses a base year of 2023.
(c) NPV of Program Cost includes a NPV of very rough estimates of OpEx savings (as a negative value) to consider potential lifetime OpEx savings in the CBR calculation.

For additional details see Exhibit (PG&E-4), WP EO-DOVHD-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

2. Alternative Plan 2: DOVHD-A002 – Grid Monitoring

PG&E leverages grid monitoring capabilities to provide greater visibility into the system for operational mitigations, including insight into distribution asset health. This alternative plan considers the implementation of several line and pole mounted technologies, such as asset sensors and SmartMeter™ devices, to address high priority threats on the distribution system that lack real-time condition monitoring. Examples include sensors that track pole lean rate of degradation and heat sensors that track operating characteristics of transformers. Smart Meters and conductor sensors also track momentary faults that signal degradation to conductor health and act as a precursor to conductor failure.

The expanded situational awareness would allow PG&E to better understand various time dependent conditions, such as weather impacts on poles, vegetation growth on conductors, and wind effects on crossarms. CBR estimates for this program are based on an assumed effectiveness and deployment in HFTD CPZs where PG&E does not have a high penetration of existing sensors (e.g., Line Sensors/EFD/DFA), though this may be adjusted as additional analysis is conducted.

This program was not considered in the base mitigation plan due to the additional analysis required to implement failure probabilities based on sensor data. The volume of data required to identify and appropriately manage the likelihood of failure is significant, as it will require testing and alignment to both equipment and environmental conditions. Moving forward, piloting of sensor programs is being considered to help provide this data and understanding.

TABLE 4-17
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[b]		
Line No.	Mitigation ID[a]	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [C]	CBR [C]/([A]+[B])
1	DOVHD-A002, WLDFR-A002	Grid Monitoring (Alternative Mitigation)	$12,634	$12,878	$12,582	$12,170	$87.1	$600.2	6.9
2		Total	$12,634	$12,878	$12,582	$12,170			

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.
(b) NPV uses a base year of 2023.
For additional details see Exhibit (PG&E-4), WP EO-DOVHD-F.
The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

PACIFIC GAS AND ELECTRIC COMPANY

RISK ASSESSMENT AND MITIGATION PHASE

CHAPTER 5

RISK ASSESSMENT AND MITIGATION STRATEGY: FAILURE OF ELECTRIC DISTRIBUTION UNDERGROUND ASSETS

PACIFIC GAS AND ELECTRIC COMPANY
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RISK ASSESSMENT AND MITIGATION STRATEGY: FAILURE OF ELECTRIC DISTRIBUTION UNDERGROUND ASSETS

A. Executive Summary

Underground (UG) assets are a key component of Pacific Gas and Electric Company's (PG&E) electrical distribution system. PG&E's electric UG distribution system consists of primary distribution cable and associated switches, vaults, enclosures, conduits, splices, cable connectors, and other equipment.

Failure of Electric Distribution UG Assets is defined as the failure of distribution UG (including both radial and network) assets or lack of remote operation functionality that may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy. In the 2020 Risk Assessment and Mitigation Phase (RAMP), a portion of this risk was presented as the Failure of Electric Distribution Network Assets, which included only the UG network systems in Oakland and San Francisco. To better manage the risk associated to this asset family, PG&E has consolidated all distribution UG assets into the new Failure of Electric Distribution UG Assets risk. The combined risk leverages outages on the UG system as a proxy for failures to support quantifying the risk. Failure of Electric Distribution UG Assets has the tenth-highest 2027 Test Year (TY) Baseline Safety Risk Value ($19.4 million) and the fifth-highest 2027 TY Baseline Total Risk Value ($727.7 million) of PG&E's 32 Corporate Risk Register (CRR) risks.

Exposure to this risk is based on the 28,724 circuit miles of distribution UG, of which 28,560 miles are UG radial cables and 164 miles are UG network. In addition, included in this population are 673 new miles of distribution UG assets added by the system hardening undergrounding program since 2021. With continued development from programs such as system hardening undergrounding and new business connects, the number of UG miles on the system is expected to continuously change and to increase significantly over the next ten years.

The primary driver for this risk is UG equipment failure, which includes transformer, conductor, connector/splice, elbow, and secondary/service failures. It is responsible for 83 percent of risk events and 76 percent of the overall risk. The largest subdrivers of UG equipment failure are transformers, conductors, and connector/splices representing a combined 78 percent of the equipment failure driver. Seismic events account for the next highest amount of risk with 8 percent, driven by the large consequence associated with a seismic event.

As PG&E focuses on high priority work related to wildfire mitigation, the focus of the current distribution UG mitigation plan is to address safety consequences associated with an UG asset failure event, specifically mitigating the smoke or explosion outcome, which accounts for 70 percent of the Safety Risk Value.

The proposed risk control strategy is to test and install new sensors to detect overheating, smoke and cable melting to mitigate the consequence of fire, smoke and explosion associated with an UG Distribution Equipment failure. Proactive maintenance programs, such as our Network Transformer Oil Sampling program, identify assets that may have higher probabilities of failure and could result in an explosion, fire or smoke event. In addition, the use of monitoring devices such as the Temperature Alarm Device (TAD) is used to monitor subsurface oil-filled transformers and alert PG&E when an asset is performing outside of its normal operating temperature allowing just-in-time maintenance or replacement of potentially failing transformers that could lead to an explosion, fire, or smoke event. Proactive equipment replacement programs, such as the Load Break Oil Rotary (LBOR) Switch Replacement Program, minimize the likelihood of a risk event, which in turn mitigates the potential consequence of an explosion, fire, or smoke event located in areas with highest public safety exposure.

Another aspect PG&E implements to mitigate the safety consequence of a distribution UG risk event is through the utilization of inspection and maintenance programs. Inspections identify components that are more likely to fail, and the maintenance program corrects the deficiency or replaces the asset. Along with our scheduled General Order (GO) 165 UG inspections, PG&E is also performing additional detailed manhole inspections, prioritizing on those located in high public consequence areas. To further enhance our ability to monitor UG assets, PG&E is exploring new technologies such as a gas monitoring device and a secondary cable monitoring device, which could potentially alert PG&E of the buildup of explosive gases in vaults or the failure of secondary cable.

Two alternative mitigation strategies to address this risk were identified around venting manhole cover replacements and radial deteriorated concentric neutrals. The venting manhole cover replacement program creates release for a buildup of pressure in vaults or other UG conduits. The radial deteriorated concentric neutrals program looks to replace the remaining unjacketed primary distribution cables in the PG&E system within the next 20 years.

1. Risk Overview

TABLE 5-1
RISK OVERVIEW

Line No.	Risk Name	Failure of Electric Distribution UG Assets
1	Definition	The failure of distribution UG (including radial and network) assets or lack of remote operation functionality may result in public or employee safety issues, property damage, environmental damage, or inability to deliver energy.
2	In Scope	Failure of primary distribution voltage UG radial and network assets.
3	Out of Scope	Failure of assets associated with UG assets for the transmission system. The associated safety consequences related to dig-ins or electrical contact are included in the Public Contact with Intact Energized Electrical Equipment risk.
4	Data Quantification Sources	PG&E records of radial outage data from 2015 to 2022 PG&E records of network equipment failures from 2008 to 2022 Electric incident reporting (EIR) dataset which maintains injury/fatality incidents within PG&E service territory Historical outage cost data from 2017 to 2020

B. Risk Assessment

1. Background and Evolution

The Failure of Electric Distribution UG Assets risks have been on the Electric Operations risk register since 2014. PG&E included Failure of

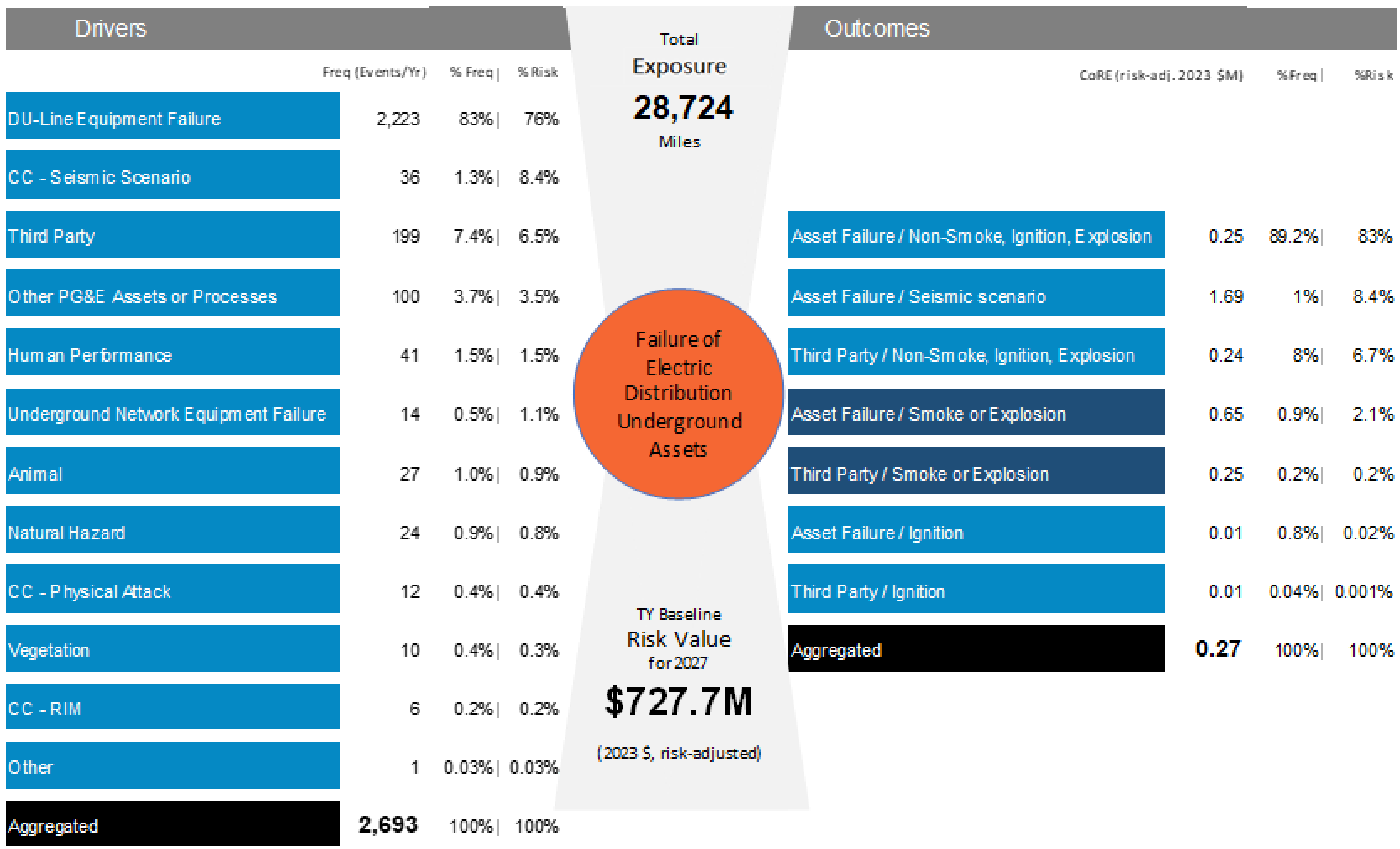
Distribution Network Assets in the 2020 RAMP filing due to a change in PG&E's assessment of the potential safety consequences of a failure incident.

In the 2024 RAMP, the Failure of Electric Distribution Network Assets is combined with Failure of Distribution UG Assets. These risks had similar driver profiles and were aggregated to better support management of the risk. Tranches were utilized to distinguish the differences in consequences of failure for network assets, due to the high-density locations they serve.

The failure of Electric Distribution UG and Network risk is a combination of a reliability risk largely driven by the radial UG system and safety risk contributed equally from the network and radial systems. Most of the consequence of this risk is realized when an asset failure results in an outage. This impact is more significant in areas of high population density, such as those locations served by network circuits. Additionally, in the event that a failure leads to a smoke, ignition, and/or explosion, these events can lead to public safety impacts.

2. Risk Bow Tie

FIGURE 5-1
RISK BOW TIE



3. Exposure to Risk

The risk exposure is based on the circuit miles of distribution underground radial and network system. The total exposure for this risk is 28,724 miles.

4. Tranches

The tranches have been broken out based on four dimensions: (1) Radial vs Network System; (2) Asset Health Need; (3) Overloading Condition; (4) Historical Likelihood of Failure

1) <u>Radial/Network (Two categories: Radial or Network)</u>

Due to the differences in risk profiles, UG radial system and the UG network system were separated. Radial systems are more prone to reliability risk, while network systems are more prone to safety risk.

2) <u>Asset Health Need (Three categories: High HN, Low HN, Min HN)</u>

Asset Health Need is a combination of several factors. Based on these factors, spans of UG mileage were classified by whether they have Health Need or not. The factors include:

- Age: Cable age exceeds expected life of 40 years within the next 10 years;
- Material: Cable types including High Molecular Weight Polyethylene (HMWPE), Paper-Insulated Lead-Covered, and Unjacketed XLP;
- Loading: Radial cable exceeding 90 percent loading by 2031 or network cable exceeding 60 percent loading by 2031;
- Other: Network cable having at least two cable failures in the last five years or radial cable having at least two sustained outages due to cable failure the last five years; and
- Deteriorated Concentric Presence: Testing identified the presence of deteriorated concentric on the circuit.

Once parts of the circuit have been identified as having a Health Need, the circuit was classified into one of 3 categories: High HN, where greater than 50 percent of the circuit is classified with a Health Need; Low HN, where less than 50 percent of the circuit is classified with a Health Need; and Min HN, where there is minimal percentage (approximately zero) of the circuit classified with a Health Need.

3) <u>Overloading (Two categories: OL or No OL)</u>

To create further separation, a tranche dimension of overloading was defined for the loading criteria. Radial cable exceeding 90 percent loading by 2031 or network cable exceeding 60 percent loading by 2031 was classified as with Overload (OL) and the rest was classified as No OL.

4) <u>Historical Outage Performance (Four categories: Q1, Q2, Q3, Q4)</u>

Radial circuits were split further into four quartiles based on the Likelihood of Risk Event (LoRE), i.e., outage frequency per mile of the circuit.

The combination of these four dimensions described above creates 48 possible tranche combinations; however, given that not every combination results in known miles, there are only 24 tranches presented (with the other combination of 24 resulting in 0). As an example, PG&E has no known network system that is experiencing an overloaded condition, so those tranches are not presented.

TABLE 5-2
TRANCHE LEVEL RISK ANALYSIS RESULTS

Line No.	Tranche	Mileage	Aggregated Risk Value	Percent Risk	Risk/Mile
1	Network-No OL-Low HN	31	2.7	0.4%	0.085
2	Radial-OL-High HN-Q1	664	49.2	6.8%	0.074
3	Radial-OL-Low HN-Q1	281	18.2	2.5%	0.064
4	Radial-No OL-High HN-Q1	1,682	102.6	14.1%	0.061
5	Network-No OL-High HN	117	6.5	0.9%	0.055
6	Radial-No OL-Low HN-Q1	847	37.9	5.2%	0.045
7	Radial-OL-High HN-Q2	1,653	72.7	10.0%	0.044
8	Radial-No OL-High HN-Q2	2,602	94.2	12.9%	0.036
9	Network-No OL-Min HN	16	0.5	0.1%	0.034
10	Radial-OL-Low HN-Q2	797	26.1	3.6%	0.033
11	Radial-OL-High HN-Q3	1,445	39.1	5.4%	0.027
12	Radial-No OL-Low HN-Q2	1,915	49.5	6.8%	0.026
13	Radial-OL-Low HN-Q3	1,905	41.1	5.6%	0.022
14	Radial-No OL-High HN-Q3	1,956	40.2	5.5%	0.021
15	Radial-No OL-Min HN-Q3	135	2.6	0.4%	0.019
16	Radial-No OL-Low HN-Q3	3,098	53.9	7.4%	0.017
17	Radial-No OL-Min HN-Q1	21	0.3	0.0%	0.015
18	Radial-OL-High HN-Q4	472	6.6	0.9%	0.014
19	Radial-No OL-High HN-Q4	1,501	17.0	2.3%	0.011
20	Radial-OL-Low HN-Q4	2,420	23.8	3.3%	0.010
21	Radial-No OL-Low HN-Q4	4,790	40.9	5.6%	0.009
22	Radial-No OL-Min HN-Q4	331	2.3	0.3%	0.007
23	Radial-No OL-Min HN-Q2	13	0.1	0.0%	0.005
24	Radial-OL-Min HN-Q4	33	0.0	0.0%	0.001

5. Drivers and Associated Frequency

PG&E identified twelve drivers (three of which are cross-cutting factors) of the Failure of Electric Distribution UG Assets risk. Each driver and its associated 2027 TY estimated frequency is discussed below.

- **D1 – DU-Line Equipment Failure:** This driver accounts for failure events due to UG assets, including transformer, primary cable, primary splice, secondary cable failure, or other equipment. These events account for 2,223 (83 percent) of the 2,693 expected annual number of failures. Within this driver, UG transformers represent 44 percent, conductors represent 22 percent, and connectors represent 12 percent of all equipment failures.
- **D2 – Seismic Scenario (Cross-Cutting):** This driver represents failure events caused by seismic activity. This risk is described further in Exhibit (PG&E-2), Chapter 3 of this report. These events account for 36 (1 percent) of the 2,693 expected annual number of failures. The

consequence associated to these events is significant, however, and the Seismic Scenario represents 8 percent of the risk.

- **D3 – Third-Party:** The third-party driver represents failure events caused by third parties, including dig in events. These events account for 199 (7 percent) of the 2,693 expected annual number of failures.
- **D4 – Other PG&E Assets or Processes:** This driver reflects failure events caused by PG&E work processes (e.g., return circuit normal) or non-UG assets, such as generators or metering equipment. The Other PG&E Assets or Processes driver accounts for 100 (4 percent) of the 2,693 expected annual number of failures.
- **D5 – Human Performance:** The human performance driver represents failure events caused by PG&E employees based on improper construction, operating error, or other actions. These events account for 41 (2 percent) of the 2,693 expected annual number of failures.
- **D6 – UG Network Equipment Failure:** This driver reflects failure events due to UG network assets, including primary cable, primary splice, secondary cable failure, or other equipment. These events account for 14 (1 percent) of the 2,693 expected annual number of failures.
- **D7 – Animal:** The animal driver considers failure events caused by animals, such as squirrels or mice. The animal driver accounts for 27 (1 percent) of the 2,693 expected annual number of failures.
- **D8 – Natural Hazard:** Natural Hazards account for failure events caused by a natural hazard event, such as flood, rain, etc. (It excludes earthquakes, which are the basis for the seismic crosscutting factor). The Natural Hazard driver accounts for 24 (<1 percent) of the 2,693 expected annual number of failures.
- **D9 – Physical Attack (Cross-Cutting):** This driver represents failure events caused by physical attack on PG&E assets. This risk is described further in Exhibit (PG&E-2), Chapter 3 of this report. These events account for 12 (<1 percent) of the 2,693 expected annual number of failures.
- **D10 – Vegetation:** This driver represents failure events caused by trees, roots, or other intrusion due to vegetation. The Vegetation driver

accounts for 10 (<1 percent) of the 2,693 expected annual number of failures.

- **D11 – Records and Information Management (RIM) (Cross-Cutting):** Failure events caused by not fully implementing an effective RIM program and controlling data quality are considered in this driver. This risk is described further in Exhibit (PG&E-2), Chapter 3 of this report. These events account for 6 (<1 percent) of the 2,693 expected annual number of failures.
- **D12 – Other:** This driver reflects failure events without known causes. The Other driver accounts for 1 (<1 percent) of the 2,693 expected annual number of failures.

6. Climate Adaptation Vulnerability Assessment Results

PG&E designed the Climate Adaptation Vulnerability Assessment (CAVA) to be consistent with the California Public Utilities Commission's (CPUC) Final Ruling on Order Instituting Rulemaking (OIR) to Consider Strategies and Guidance for Climate Change Adaptation (Rulemaking 18-04-019). The methodology outlined by D.20-08-046 requires utilities to perform an assessment of all assets, operations, and services that may be impacted by future risks from climate change related to changes in temperatures, precipitation and flooding, sea level rise, wildfire, and drought-driven subsidence.

PG&E's CAVA addresses actual or expected climatic impacts on the electric distribution system, with a focus on the 2050 decadal time period. The CAVA assessment on PG&E's Electric Distribution Assets considered impacts to utility planning, facilities maintenance and construction, and communications, to maintain safe, reliable, affordable, and resilient operations.[1]

The CAVA results consider all Electric Distribution assets, including UG assets. The CAVA climate risk findings consider generalized impacts from future climate hazards to all electric distribution assets that could have significant consequences for customers, public safety, and the environment. The CAVA did not separately assess UG and above ground electric

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1 PG&E's CAVA, Section 3.1.1.c Electric Distribution (to be published May 15, 2024).

distribution assets or the mitigation and controls in place. As a result, all electric distribution assets have the same climate risk and adaptive capacity rankings.

TABLE 5-3
ELECTRIC DISTRIBUTION CLIMATE ADAPTATION VULNERABILITY ASSESSMENT CLIMATE RISK SCORES

Line No.	Climate Hazard	Adaptive Capacity	Climate Change Risk
1	Temperature	Moderate	High
2	Flooding/Precipitation	Moderate	Moderate
3	Sea Level Rise	Moderate	Moderate
4	Wildfire	High	High
5	Drought-driven subsidence	High	Low (off-ramped)

The adaptive capacity of PG&E's electric distribution assets to future climate hazards were a key factor in determining the company's climate risk rankings. Adaptive capacity is defined as the ability of an asset or system to moderate or eliminate identified climate vulnerabilities as assessed based on 2050 conditions and mitigate future impacts. This included any aspect of design, planning, operations, monitoring, emergency response capacities, and other PG&E capabilities. PG&E's CAVA found that electric distribution's current mitigations and controls result in high adaptive capacity to address climate risks associated with wildfires and drought-driven subsidence and moderate adaptive capacity to address climate risks from flooding/precipitation, sea level rise, and extreme temperatures. These mitigations include increased investments in distribution capacity projects and updating design standards to increase the size of transformers at replacement to account for increased load associated with temperature rise.

7. Cross-Cutting Factors

A cross-cutting factor is a driver, component of a driver, or a consequence multiplier that impacts multiple risks. PG&E is presenting seven cross-cutting factors in the 2024 RAMP. The cross-cutting factors that impact the Failure of Electric Distribution Underground Assets risk are shown in Table 5-4 below.

TABLE 5-4
CROSS-CUTTING FACTOR SUMMARY

Line No.	Cross-Cutting Factor	Impacts Likelihood	Impacts Consequence
1	Climate Change	Yes	No
2	Cyber Attack	Yes*	Yes*
3	Emergency Preparedness and Response	Yes*	Yes*
4	Information Technology Asset Failure	Yes*	Yes*
5	Physical Attack	Yes	No
6	RIM	Yes	Yes*
7	Seismic	Yes	Yes

Yes The cross-cutting factor has been quantified in the model.

Yes* The cross-cutting factor does influence the baseline risk but has not been quantified in the model, or the cross-cutting factor may influence the baseline risk but further study is needed.

No The cross-cutting factor does not meaningfully influence the baseline risk.

A description of the cross-cutting factors and the mitigations and controls that PG&E is proposing to mitigate the cross-cutting factors is in Exhibit (PG&E-2), Chapter 3.

a. Climate Change

PG&E incorporates escalating risk event frequency of Natural Hazard driver over time due to climate change. Each of the five sub-drivers of Natural Hazard driver incorporated in the risk Bow Tie has a unique escalation pathway computed using relevant climate data for California and/or PG&E's service territory. The escalation factors for Flood sub-driver frequency are based on extreme precipitation modeling, looking at the number of days in a water year with five-day rainfall totals exceeding the 95th percentile. The escalation factors for Rain sub-driver Frequency are based on an analysis of Major Rain Event days per year due to Atmospheric River Storms. The escalation factors for Ice/Snow sub-driver frequency are based on analysis of days with extreme precipitation and average temperatures below freezing. The escalation factors for Fire- Forest/Grass sub-driver frequency are based on the expected increase in number of acres burned. Finally, the escalation factors for Lightning sub-drivers are based on projected future lightning strike rates in California.

b. Physical Attack

Within the third-party driver, both theft and vandalism are included as sub-drivers. These events can lead to outages on the distribution UG system, causing both reliability and financial damages.

c. Records and Information Management

Improper construction, inaccurate records, and inaccurate locations of PG&E distribution UG assets can affect the risk. Inaccurate records can affect the frequency of asset failures. The increased frequency, as seen by this driver, would be considered if records are lost on locations of assets, resulting in additional dig-in events where assets were unknown or where maintenance and repair activities could not take place due to unknown conditions or characteristics of UG assets.

d. Seismic

A large enough seismic event would lead to widespread outages on the distribution UG system, as conductors would shift orientation, separate, and require replacement. A severe seismic event could result in substantial portions of the UG system being impacted and would result in extended outages and difficult restoration. The frequency of an event of this magnitude is evaluated to be relatively small, but the consequences would be widespread and significant.

8. Consequences

The Failure of Electric Distribution UG Assets consequence outcomes separates out incidents by asset failure and third-party events. Each outcome has an additional dimension where the event results in: (1) non-smoke or explosion, (2) smoke or explosion, or (3) ignition. Each additional outcome represents an escalating significance of the outcome that can lead to a potential safety event. An additional outcome was also added to assess the impact of a seismic scenario. In total, these combinations result in seven unique outcomes. Additional detail on the consequence of each of these outcomes is provided in Table 5-5.

<u>Asset Failure</u>

- **Non-Smoke, Ignition, Explosion:** This outcome occurs when an asset failure results in an outage but does not result in an explosion, smoke, or an ignition. As the most common outcome, it comprises 89 percent of the risk events and makes up 83 percent of the overall risk. Its event frequency contribution greater than the contribution to the risk highlights that these events are less severe than other outcomes, mostly in safety consequences from an event.

- **Smoke or Explosion:** This outcome occurs when an asset failure results in an outage but also results in smoke or explosion. This is a low occurrence, representing about 0.9 percent of the events and makes up 2.1 percent of the risk. The larger attribution of risk compared to frequency highlights the increased impact that these events have, given the release of energy or explosion associated to this set of outcomes.
- **Ignition:** This outcome occurs when an asset failure results in an ignition. It represents 0.8 percent of the events and makes up <0.1 percent of the risk. The low contribution to risk is due to the ignition outcome itself being captured in the Wildfire risk.

Third-Party

- **Non-Smoke, Ignition, Explosion:** This outcome occurs when an outage is caused by a third party but does not result in an explosion, smoke, or an ignition. This outcome represents 8 percent of the events and makes up 6.7 percent of the risk. It highlights events that are less severe than other outcomes due to the lack of smoke, explosion, or ignition, and is slightly less severe than asset failure events. The direct public safety impacts of third-party events are in the scope of Public Contact with Intact Energized Electrical Equipment (PCEEE) and not included in this risk.
- **Smoke or Explosion:** This outcome occurs when an outage is caused by a third party and results in an explosion, smoke, or an ignition. This outcome represents <1 percent of the events and makes up 0.2 percent of the risk. It highlights events that are more severe than other outcomes due to potential safety impacts from smoke and explosion. While the direct public safety impacts of third-party events are in the scope of PCEEE risk and not included in this risk, this outcome is separated to highlight the exposure these outcomes pose.

- **Ignition:** This outcome occurs when a third-party event results in an ignition. This outcome represents <0.1 percent of the events and makes up <0.1 percent of the risk. The low contribution to risk is due to the ignition outcome itself being captured in the Wildfire risk.

Asset Failure/Seismic Scenario

This outcome occurs when there is a seismic cross-cutting event. The Seismic Scenarios are described in Exhibit (PG&E-2), Chapter 3.

TABLE 5-5
RISK EVENT CONSEQUENCE

Line No.		Natural Units Per Event				Expected Loss per Year (2023 $million				Attribute Risk Score			
		Safety	Indirect Safety	Electric Reliability	Financial	Safety	Indirect Safety	Electric Reliability	Financial	Safety	Indirect Safety	Electric Reliability	Financial
		EF/ event	EF/ event	MCMI/ event	$M/event	$M/yr	$M/yr	$M/yr	$M/yr	$M/yr	$M/yr	$M/yr	$M/yr
1	Asset Failure/ Non-Smoke, Ignition, Explosion	–	0.00007	0.08	0.01	–	2.56	577.75	20.41	–	2.56	577.76	20.41
2	Asset Failure/ Seismic scenario	0.0066	0.003	0.45	0.01	3.63	1.49	50.95	0.20	4.54	1.68	54.62	0.20
3	Third Party/ Non-Smoke, Ignition, Explosion	–	0.00007	0.07	0.01	–	0.21	46.51	1.72	–	0.21	46.51	1.72
4	Asset Failure/ Smoke or Explosion	0.0197	0.00008	0.07	0.01	7.17	0.03	5.06	0.20	10.35	0.03	5.06	0.20
5	Third Party/ Smoke or Explosion	–	0.00007	0.08	0.01	–	0.01	1.60	0.06	–	0.01	1.60	0.06
6	Asset Failure/ Ignition	–	–	–	0.01	–	–	–	0.17	–	–	–	0.17
7	Third Party/ Ignition	–	–	–	0.01	–	–	–	0.01	–	–	–	0.01
8	Aggregated	0.0003	0.0001	0.08	0.01	14.88	4.30	685.55	22.76	14.88	4.49	685.55	22.76

C. 2023-2026 Control and Mitigation Plan

Tables 5-6 and 5-7 list the controls and mitigations that PG&E included in its 2020 RAMP, 2023 General Rate Case (GRC) and 2024 RAMP (2023-2026 and 2027-2030) and provide an evolution of the programs from each filing. In the subsequent sections, PG&E describes the baseline controls and mitigations proposed for the 2027-2030 period. A description of the cross-cutting factors and the mitigations and controls that PG&E is proposing to mitigate the cross-cutting factors is in Exhibit (PG&E-2), Chapter 3.

TABLE 5-6
CONTROLS SUMMARY

Line No.	Control Number and Name[(a)]	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2023-2026)	2024 RAMP (2027-2030)
1	C1 – Network Cable Replacement and Switch Installations	X	Becomes DNTWK-C001		
2	C2 – Network Maintenance and Corrective Work	X	Becomes DNTWK-C002		
3	C3 – Network Component (Transformer, Protector) Replacements Condition Based	X	Becomes DNTWK-C003		
4	C4 – Asset Information Improvements/Asset Data Comparison and Updates	X			
5	C5 – Network Health Report (Units Offline)	X			
6	C6 – Standards, Processes, and Training	X			
7	DNTWK-C001 – Network Cable Replacement		X	Becomes DUNGD-C011	
8	DNTWK-C002 – Maintenance and Corrective work		X	Becomes DUNGD-C012	
9	DNTWK-C003 – Network Component (Transformer, Protector) Replacements-Condition Based		X	Split into DUNGD-C014 and DUNGD-C015	
10	DUNGD-C001 – Patrols		X	Becomes DUNGD-C001	
11	DUNGD-C002 – UG Notifications		X	X	X

TABLE 5-6
CONTROLS SUMMARY
(CONTINUED)

Line No.	Control Number and Name	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2023-2026)	2024 RAMP (2027-2030)
12	DUNGD-C003 – Equipment Maintenance and Replacement		X	Becomes DUNGD-C003	
13	DUNGD-C004 – Planned Major Projects		X		
14	DUNGD-C005 – UG Idle Facility Removal		X		
15	DUNGD-C007 – LBOR Switch Replacement		X	X	X
16	DUNGD-C008 – UG Transformers Temperature Sensor		X	X	X
17	DUNGD-C06A – Primary Cable Replacement Program		X	Becomes DUNGD-C006	
18	DUNGD-C06B – Primary Cable Rejuvenation Program		X		
19	DUNGD-C001 – UG Patrols			X	X
20	DUNGD-C003 - UG General Equipment Maintenance and Replacement			X	X
21	DUNGD-C006 - Primary Cable Replacement Program			X	X
22	DUNGD-C010 - UG Inspections			X	X
23	DUNGD-C011 - Network Cable Replacement			X	X
24	DUNGD-C012 - Network Maintenance and Corrective Work [Transformer Maintenance and Testing]			X	X
25	DUNGD-C014 – Network Component (Transformer, Protector) Replacements – Condition Based [Transformer]			X	X
26	DUNGD-C015 – Network Component (Transformer, Protector) Replacements – Condition Based [Protector]			X	X
27	DUNGD-C016 – Locate and Mark – Distribution			X	X
28	DUNGD-C017 – Public Safety Awareness			X	X

(a) Controls included in the 2020 RAMP do not start with Risk ID such as DNTWK and DUNGD, distinguishing between Control Numbers used in the 2020 RAMP Report and Control Numbers used in the 2023 GRC and 2024 RAMP.

TABLE 5-7
MITIGATIONS SUMMARY

Line No.	Control Number and Name[a]	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2023-2026)	2024 RAMP (2027-2030)
1	M1 – Network Component Replacements – High-Rise Oil-Filled Transformers	X	Becomes DNTWK-M001		
2	M2 – Venting Manhole Cover Replacements	X	Becomes DNTWK-M002		
3	M3 – Installation of Supervisory Control and Data Acquis (SCADA) Equipment for Safety Monitoring	X		Becomes DUNGD-M003	
4	M4 – Incremental Primary Network Cable Replacements	X	Becomes DNTWK-M004		
5	M5 – Network Component Replacements – Targeted Replacement of Dry-Type Transformers in High-Rise Buildings	X	Becomes DNTWK-M005		
6	M6 – Network Component Replacements – Targeted Replacement of Closing Mechanism Drawout (CMD)-Type Network Protectors	X		Becomes DUNGD-M008	
7	DNTWK-M001 – Network Component Replacements – Targeted Replacement of Oil Filled Transformers in High-Rise Buildings		X		
8	DNTWK-M002 – Venting Manhole Cover Replacements		X	Becomes DUNGD-M002	
9	DNTWK-M003 – Network Component Replacements – Targeted Network Protector Replacement		X	Becomes DUNGD-M008	
10	DNTWK-M004 – Incremental Primary Network Cable Replacements		X		
11	DNTWK-M005 – Network Component Replacements – High-Rise Dry-Type Transformers		X	Split into DUNGD-M006 DUNGD-M007	
12	DNTWK-M006 – Network Component Replacements – Targeted Network Protector Replacement		X		
13	DUNGD-M002 – Network Venting Manhole Cover Replacements				
14	DUNGD-M003 – Network Installation of SCADA Equipment for Safety Monitoring			X	X
15	DUNGD-M006 – Network Component Replacements – High-Rise Dry-Type Transformers [Transformer]			X	X
16	DUNGD-M007 - Network Component Replacements - High-Rise Dry-Type Transformers [Protector]			X	X
17	DUNGD-M008 – Network Component Replacements – Targeted Network Protector Replacement CMD-Type			X	X

1. Controls

- **DUNGD-C002 – UG Notifications:** The UG Notifications control program addresses and repairs UG facilities or replaces individual components that are not an imminent hazard and have not caused an outage. It includes cleaning enclosures, re-securing equipment, resurfacing lids, work related to UG transformers, and tagging. Addressing UG notifications through this program maintains the overall health of the UG system and reduces equipment failure drivers associated to the UG risk model.
- **DUNGD-C003 – UG General Equipment Maintenance and Replacement:** The UG General Equipment Maintenance and Replacement program consists of programs that are focused on replacing deteriorated UG facilities that are not an imminent hazard and have not caused an outage. Facilities include leaking transformers, conduit, enclosures, pads, and idle equipment. This program addresses non-conformance identified by preventative maintenance programs, such as inspections and patrols, as well as internal operational processes.
- **DUNGD-C006 – Primary Cable Replacement Program:** The Reliability Related Cable Replacement program replaces UG distribution primary cable based on reliability performance, age, and/or a combination of these factors and other influences. Replacement candidates are primarily identified in areas (protective zones) experiencing two or more cable failures within five years. In addition, the program also replaces cables tested with deteriorated concentric (neutral) wires on unjacketed cables. As part of PG&E's transition to integrated grid planning to prioritize Wildfire Mitigation and Capacity investments, UG Distribution mitigations and controls will focus on mitigating the primary safety consequence associated with an UG failure event, which accounts for 70 percent of the direct safety consequence. Given that the Primary Cable Replacement Program focuses on mitigating reliability risk, this mitigation will continue with minimal cable replacement between 2023 and 2026.

- **DUNGD-C007 – LBOR Switch Replacement:** The LBOR Switch Replacement program proactively identifies and replaces UG oil-filled switches. The switches targeted for replacement are selected based on asset condition when it warrants replacement to avoid potential failures. This control addresses UG equipment failure, specifically regarding switch failure.
- **DUNGD-C011 – Network Cable Replacement:** This control consists of the systematic replacement of network cable assets in the downtown San Francisco and Oakland networks. Many of the existing network primary and secondary cables date from the 1920s to the 1960s and are nearing the end of their useful life. The network systems replacement program is an ongoing program that started in 2011. The program work includes replacing primary and secondary cables and modifying network transformers to accept the new primary cables. Similar to the Primary Cable Replacement program described above, as part of PG&E's transition to integrated grid planning to prioritize Wildfire Mitigation and Capacity investments, UG Distribution mitigations and controls will focus on mitigating the primary safety consequence associated with an UG failure event. Given that the Network Cable Replacement Program focuses on mitigating reliability risk, this control will continue with minimal cable replacement between 2023 and 2026.
- **DUNGD-C012 – Network Maintenance and Corrective Work [Transformer Maintenance and Testing]**: Maintenance work associated with PG&E's Network Asset Management Plan includes inspection and oil sampling of all major oil-filled network components of transformers, inspection and testing of network protectors, maintenance and routine replacement of the network SCADA system, and electric corrective notification work in network vaults. This control has the potential to reduce the UG Network Equipment Failure driver, which includes reducing the consequence of an explosion, smoke, or fire event.
- **DUNGD-C014 – Network Component (Transformer, Protector) Replacements Condition Based [Transformer]**: The Network Component Replacements Program replaces network transformers

identified for replacement (due to their condition) with new, safer, and more reliable technologies. Replacement transformers are either explosion resistant or dry type and use a single tank design to minimize the risk of catastrophic failure. PG&E routinely monitors the condition of its network transformers by means of inspection, insulating oil analysis, testing, and online sensor monitoring. This control addresses transformer failures under the UG Network Equipment Failure driver, which includes reducing the consequence of an explosion, smoke, or fire event.

- **DUNGD-C015 – Network Component (Transformer, Protector) Replacements Condition Based [Protector]**: This program replaces network protectors identified as needing replacement (due to their condition) with new, safer, and more reliable technologies. Network protectors are usually replaced at the same time as transformers since they have a similar life span. This control addresses potential transformer or protector failures. It reduces the UG Network Equipment Failure driver, which includes reducing the consequence of an explosion, smoke, or fire event.
- **DUNGD-C016 – Locate and Mark – Distribution:** The Locate and Mark Program provides the physical location for PG&E's UG assets to PG&E crews, contractors, and third parties who plan to excavate near those assets. Providing these locations reduces the likelihood excavators will encounter UG assets. The program also includes the standby process where a PG&E field employee monitors excavation activity in a watch and protect capacity to prevent damage to PG&E facilities and reduce potential safety impacts. This mitigates third-party drivers and human performance drivers.
- **DUNGD-C017 - Public Safety Awareness:** PG&E's Public Safety Awareness Program leverages different communication vehicles to provide educational outreach activities for third parties that may or may not be customers of PG&E but operate their business in PG&E territory. Communications may include mailers, e-mails, and educational material distribution on safe practices around PG&E assets through proper

operation of equipment and excavation practices. The program support includes (but is not limited to) the following areas:

- Third-Party Contractor and Agriculture – This group includes third-party contractors, construction, agriculture, and excavation companies;
- Tree and Orchard Workers – This group focuses on distributing outreach to over 67,000 mailers towards third-party vegetation management companies;
- Emergency Preparedness Support Services – This area educates first responders on public safety around utility assets. As emergency support services are the first responders to public safety incidents, educational materials on safety around utility assets help maintain safety for the public; and
- School Public Safety Education – This effort focuses on distributing outreach to over 30,000 mailers towards educators and students in the service territory. This involves a package of classroom materials tailored to increase awareness of utility issues and change behaviors of teachers, students, and student families in the service territory.

Social media and bill insert campaigns educate PG&E customers and the public about power line safety and the hazards associated with energized electrical assets. These programs are intended to reduce the number of third-party electrical contacts, focused on the residential population.

2. Mitigations

PG&E has the following mitigations in place for the Failure of Electric Distribution UG and Network Assets risk between 2023 and 2026:

- **DUNGD-M002 – Network Venting Manhole Cover Replacements:** The Network Venting Manhole Cover Placement program was established in 2010 as a proactive mitigation and the scope was largely completed in 2022. In 2023, PG&E identified an additional approximately 400 network manhole covers that were not originally identified in scope of the existing program. These additional units are considered for proactive replacement as part of an alternative plan described in DUNGD-A001.

PG&E updated its standard in 2022 to establish hinged venting manhole covers as the standard cover for all new and rebuilt manholes. This hinged venting manhole cover stays in place during a vault explosion and reduces the potential for exposure to hot gasses from the vault, eliminating the risk of a projectile manhole cover and force of the explosion. In the event a standard-size manhole cover needs to be replaced, PG&E requires the replacement to be hinged venting manhole covers in accordance with the updated standard to continually improve the risk reduction associated mitigating the consequence of a fire, smoke, or explosion event.

- **DUNGD-M006 – Network Component Replacements – High-Rise Dry-Type Transformers [Transformer]:** PG&E is planning to replace older dry type transformers located in high-rise buildings. A total of 22 of these older dry type transformers have been identified, with most installed in the 1980s. These units are at, or nearing, the end of their useful lives and experience asset health concerns, including rust and other corrosion. This mitigation reduces the UG Network Equipment Failure driver, which includes reducing the consequence of an explosion, smoke, or fire event.
- **DUNGD-M007 – Network Component Replacements – High-Rise Dry-Type Transformers [Protector]:** This program is the similar program as DUNGD-M006 but replaces network protectors, usually replaced at the same time as transformers since they have a similar life span.
- **DUNGD-M008 – Network Component Replacements – Targeted Network Protector Replacement CMD-Type:** Based on service records, PG&E has concluded that CMD network protectors are more difficult to repair and replace, as they are an older style and have obsolete components. This program aims to replace targeted CMD units in the PG&E network with more reliable network protector models to increase system resilience and to reduce potential outage duration due to repair difficulty. It also reduces the UG Network Equipment

Failure driver, which includes reducing the consequence of an explosion, smoke, or fire event.

TABLE 5-8
2024-2026 PLANNED MITIGATIONS

Line No.	Mitigation ID	Mitigation Name	Planned Units of Work: Unit of Measurement[(a)]	2024	2025	2026	Total
1	DUNGD-M006	Network Component Replacements – High-Rise Dry-Type Transformers [Transformer]	# of Transformers	2	2	2	6
2	DUNGD-M007	Network Component Replacements – High-Rise Dry-Type Transformers [Protector]	# of Network Protectors	2	2	2	6
3	DUNGD-M008	Network Component Replacements – Targeted Network Protector Replacement CMD-Type	# of Network Protectors	4	4	3	11

(a) The units of work are presented as used in the RAMP model because the model requires that units of work are standardized. These may differ in some instances from "rate case" units – the units referred to in PG&E's GRC or other proceedings.

Note: For additional details see Exhibit (PG&E-4), WP EO-DUNGD-F.

The estimated costs for the mitigation work planned for the 2024-2026 period are shown in Table 5-9 below.

TABLE 5-9
MITIGATION COST ESTIMATES
2024-2026 CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Mitigation ID	Mitigation Name	2024	2025	2026	Total
1	DUNGD-M006	Network Component Replacements - High-Rise Dry-Type Transformers [Transformer]	$903	$903	$903	$2,709
2	DUNGD-M007	Network Component Replacements - High-Rise Dry-Type Transformers [Protector]	97	97	97	291
3	DUNGD-M008	Network Component Replacements - Targeted Network Protector Replacement CMD-Type	194	194	146	534
4		Total	$1,194	$1,194	$1,146	$3,534

Note: For additional details see Exhibit (PG&E-4), WP EO-DUNGD-F.
The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

3. Foundational Activities

As discussed in Exhibit (PG&E-2), Chapter 2, foundational activities are programs that enable two or more control or mitigation programs but do not directly reduce the consequences or the likelihood of risk events. The narrative below describes foundational activities that meet this definition and includes information on the control or mitigation programs enabled.

- **DUNGD-C001 – UG Patrols:** UG Patrols consist of visual inspection of UG electric distribution facilities to identify obvious structural problems or hazards in compliance with GO 165 and the Electric Distribution Preventive Maintenance (EDPM) Manual. Patrolled facilities include pad mounted equipment, primary enclosures, and visible secondary enclosures outside the substation fence to the end of the line. A UG patrol may be performed by walking or driving. This control is conducted to maintain compliance with GO 165 and supports the DUNGD-C002 – UG Notifications and DUNGD-C003 – UG General Equipment Maintenance and Replacement control programs. This is done through the identification of maintenance notifications.
- **DUNGD-C008 – UG Transformers Temperature Sensor**: The UG Transformer Temperature Sensor program installs distribution temperature sensors (otherwise known as TADs) on subsurface distribution assets. These assets include subsurface transformers,

LBOR switches, and 600 ampere mainline switches. These sensors provide additional situational awareness related to these subsurface assets and can identify when asset conditions need to be addressed due to increased operating temperature. These sensors enable DUNGD-C014, DUNGD-C015, and DUNGD-C003 through identification of transformers that are operating outside of standards and are in need replacement or repair. Additionally, this program will be expanded to include the installation of gas monitoring sensors to detect smoke and gases associated with cable faults. Secondary current sensors that are designed to detect faults on secondary conductor are also being considered in the expansion. These controls are focused on identifying UG failures early enough to prevent the consequence of an explosion, fire, or smoke event, which accounts for 70 percent of the Direct Safety Risk Value.

- **DUNGD-C010 – UG Inspections**: Detailed inspections of UG electric distribution facilities are performed to examine and to record any compelling, abnormal conditions that will adversely impact safety or reliability for compliance with GO 165 and the EDPM Manual. Inspected facilities include pad-mounted facilities, as well as all UG equipment, conductors, splices, and elbows within primary enclosures. It includes primary metering that provides visibility into all visible, primary cable up to a termination point plus the primary metering facilities. An infrared inspection must be performed in conjunction with UG inspections. This control is conducted to maintain compliance with GO 165 and supports the DUNGD-C002 and DUNGD-C003 controls through the identification of maintenance notifications.
- **DUNGD-M003 – Network Installation of SCADA Equipment for Safety Monitoring**: This is a targeted program to upgrade PG&E's original 1980s vintage SCADA monitoring equipment. The upgraded system provides additional equipment condition information, which allows PG&E to identify equipment conditions that can be addressed before in-service failure occurs. It also allows PG&E to operate some equipment in network vaults remotely, instead of sending crews to the vault to operate or collect information on the equipment manually. This

mitigation is conducted to maintain to support the DUNGD-C011, DUNGD-C014, and DUNGD-C015 control programs.

TABLE 5-10
FOUNDATIONAL ACTIVITIES

Line No.	Foundational Activity ID	Foundational Activity Name	Foundational Activity Description	Enabled Control and Mitigation IDs[(a)]	2027-2030 Millions of Dollars (NPV)[(b)]
1	LOCDM-C025	Dig-In Reduction Team	See description in Exhibit (PG&E-3), Chapter 2.	DUNGD-C016, PCEEE-C001, LOCDM-C017	$8.36
2	DUNGD-C001	UG Patrols	See description above	DUNGD-C002, DUNGD-C003	5.29
3	DUNGD-C008	UG Transformers Temperature Sensor	See description above	DUNGD-C003, DUNGD-C014, DUNGD-C015	23.72
4	DUNGD-C010	UG Inspections	See description above	DUNGD-C002, DUNGD-C003	29.22
5	DUNGD-M003	Network Installation of SCADA Equipment for Safety Monitoring	See description above	DUNGD-C011, DUNGD-C014, DUNGD-C015	22.72
6		Total			$89.31

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

(b) NPV uses a base year of 2023.

Note: For additional details see Exhibit (PG&E-4), WP EO-DUNGD-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

D. 2027-2030 Proposed Control and Mitigation Plan

1. Changes to Controls

As described in Sections C.1, the controls that have been implemented to address the Distribution UG Asset Failure risk will continue through 2027-2030. Table 5-11 below shows the cost estimates, risk reduction values, and CBRs for these programs as planned for the 2027–2030 time period.

TABLE 5-11
CONTROLS COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030

			Thousands of Nominal Dollars				Millions of Dollars (NPV) [b]			
Line No.	Control ID [a]	Control Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[c] [C]/([A]+[B])
1	DUNGD-C002	UG Notifications	$9,244	$9,244	$9,244	$9,244	$25.6	$6.7	$208.4	6.5
2	DUNGD-C003	UG General Equipment Maintenance and Replacement	27,521	27,521	27,521	27,521	105.7	50.5	275.3	1.8
3	DUNGD-C006	Primary Cable Replacement Program	17,680	29,945	29,679	42,136	112.3	–	92.8	0.8
4	DUNGD-C007	LBOR Switch Replacement	12,357	12,604	12,856	13,113	48.8	–	44.1	0.9
5	DUNGD-C011	Network Cable Replacement	258	2,733	4,550	8,706	14.4	17.2	34.6	1.1
6	DUNGD-C012	Network Maintenance and Corrective Work [Transformer Maintenance and Testing]	1,541	1,541	1,541	1,541	4.3	–	21.8	5.1
7	DUNGD-C014	Network Component (Transformer, Protector) Replacements - Condition Based [Transformer]	1,037	1,037	1,124	1,168	4.2	5.9	8.0	0.8
8	DUNGD-C015	Network Component (Transformer, Protector) Replacements - Condition Based [Protector]	111	111	121	126	0.4	0.6	0.1	0.1
9	DUNGD-C016, PCEEE-C001, LOCDM-C017	Locate and Mark – Distribution	85,971	84,252	82,567	80,916	231.1	8.5	113.3	0.5
10	DOVHD-C024, DUNGD-C017, PCEEE-C002	Public Safety Awareness	1,588	1,588	1,588	1,588	4.4	–	33.6	7.6
11	Total		$157,308	$170,576	$170,792	$186,058				

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.
(b) NPV uses a base year of 2023.
(c) CBR calculations include allocated Foundational Activity Program costs.

Note: For additional details see Exhibit (PG&E-4), WP EO-DUNGD-F.
The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

2. Changes to the Mitigation

As PG&E focuses on high priority work related to wildfire mitigation, the focus of 2027-2030 distribution UG mitigation plan is to continue to control and mitigate the safety risks associated with the consequence of an explosion, smoke, or fire event, which accounts for 70 percent of the Direct Safety Risk Value. The mitigations discussed in section C.2 will continue through 2027-2030. The amount of work PG&E plans for each mitigation is shown in Table 5-12 below.

TABLE 5-12
2027-2030 PLANNED MITIGATIONS

			Planned Units of Work					
Line No.	Mitigation ID	Mitigation Name	Unit of Measure[(a)]	2027	2028	2029	2030	Total
1	DUNGD-M006	Network Component Replacements – High-Rise Dry-Type Transformers [Transformer]	# of Transformers	2	2	2	2	8
2	DUNGD-M007	Network Component Replacements – High-Rise Dry-Type Transformers [Protector]	# of Network Protectors	2	2	2	2	8
3	DUNGD-M008	Network Component Replacements – Targeted Network Protector Replacement CMD-Type	# of Network Protectors	3	3	1	–	7

(a) The units of work are presented as used in the RAMP model because the model requires that units of work are standardized. These may differ in some instances from "rate case" units—he units referred to in PG&E's GRC or other proceedings.

Note: For additional details see Exhibit (PG&E-4), WP EO-DUNGD-F.

Table 5-13 below shows the costs estimates, risk reduction values, and CBRs for the mitigation planned for the 2027–2030 time period.

TABLE 5-13
MITIGATION COST ESTIMATES, RISK REDUCTION, CBR, AND FACTORS AFFECTING SELECTION
2027-2030 CAPITAL

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[(a)]				
Line No.	Mitigation ID	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[(b)] [C]/([A]+[B])	Factors Affecting Selection
1	DUNGD-M006	Network Component Replacements – High-Rise Dry-Type Transformers [Transformer]	$903	$903	$903	$903	$3.5	–	$1.2	0.3	Risk Tolerance, Modeling Limitations
2	DUNGD-M007	Network Component Replacements – High-Rise Dry-Type Transformers [Protector]	97	97	97	97	0.4	–	1.2	3.2	
3	DUNGD-M008	Network Component Replacements – Targeted Network Protector Replacement CMD-Type	146	146	49	–	0.3	–	0.0	0.1	Operational and Execution Concerns
4	Total		$1,146	$1,146	$1,049	$1,000					

(a) NPV uses a base year of 2023.

(b) CBR calculations include allocated Foundational Activity Program costs.

Note: For additional details see Exhibit (PG&E-4), WP EO-DUNGD-F.
The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

3. Factors Affecting Mitigation Selection

Table 5-13 summarizes PG&E's proposed mitigations to address the Failure of Electric Distribution UG Assets. The control and mitigation of risk to the radial system is primarily through the existing control programs and the identification and replacement of known at-risk assets through the inspections and maintenance programs. The proposed mitigations that have a CBR less than 1.0 support the continued reliability of the network system as well as reduce potential downtime, and also mitigate the potential for catastrophic events as described further below:

- **Risk Tolerance**: The Commission has recognized the need for discussion and clear guidance on Risk Tolerance and has expressed its intention to address this topic in future Phases of the Risk OIR. In the meantime, PG&E's risk mitigation strategies are selected to ensure that safety remains PG&E's top priority even when the quantitative RAMP modelling indicates the costs are higher than the modeled value of risk reduction. The mitigation below addresses the risk of catastrophic equipment failure that could result in a serious injury or fatality.
  - DUNGD-M006 – Network Component Replacements – High-Rise Dry-Type Transformers [Transformer]: This mitigation is directed at reducing the UG Network Equipment Failure driver, which includes reducing the consequence of an explosion, smoke, or fire event that might otherwise result in serious injuries or fatalities.
- **Operational and Execution Concerns**: The Targeted Network Protection Replacement programs target assets that are old and no longer standard to the configuration of the system. The CMD type network protectors have become obsolete, with difficult to find components making repair more difficult or impossible, time consuming, and costly. By replacing these protectors completely, risk can be removed from the system and future repairs and restoration activities can be reduced in duration. Similarly, costs related to these non-standard or difficult to source components can be reduced as well.
- **Modeling Limitations**: The Network Component Replacements - High-Rise Dry-Type Transformers program reduces the UG Network Equipment Failure driver, which includes reducing the

consequence of an explosion, smoke, or fire event. Current RAMP modeling provides limited ability to indicate the effectiveness of targeting for programs addressing known areas of higher risk in high rises within the network. The financial consequence of these failures is potentially under-represented for network equipment repairs, as this cost is based across all UG outages and failures, not just those associated with network equipment replacement.

E. Alternative Mitigations Analysis

In addition to the proposed mitigations described in Section C above, PG&E also considered alternative mitigations. PG&E describes each of the alternative mitigations it considered below and then provides Table 5-14 and Table 5-15 showing the cost estimates, risk reduction values, and CBRs for each of the Alternative Plans.

1. Alternative Plan 1: DUNGD-A001 – Venting Manhole Cover Replacements (Alternative Mitigation)

There are approximately 4,000 (including 400 in network) non-venting covers that require retrofit to a venting cover across PG&E's distribution system (network and radial). PG&E has considered an alternative plan to proactively replace manhole covers using the Public Safety Consequences model to determine the prioritization of vaults to be replaced. This supports reducing the potential safety impacts associated to equipment failures.

Continuing the venting manhole cover replacement was not included in the plan due to the lower risk that manhole covers have comparative to other safety-related work. If the risk understanding evolves further, the program will be reassessed for inclusion in the mitigation portfolio.

TABLE 5-14
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[a]		
Line No.	Mitigation ID	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	DUNGD-A001	Venting Manhole Cover Replacements (Alternative Workplan)	$1,191	$1,191	$1,191	$1,191	$4.6	$1.2	0.3
2		Total	$1,191	$1,191	$1,191	$1,191			

(a) NPV uses a base year of 2023.

For additional details see Exhibit (PG&E-4), WP EO-DUNGD-F.

Note: The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

2. Alternative Plan 2: DUNGD-A002 – Radial Deteriorated Concentric Neutrals (Alternative Mitigation)

This alternative plan considers replacing the remaining unjacketed primary distribution cables in the PG&E system within 20 years. The estimated remaining inventory of these type of cables is 7,368 circuit miles. The unjacketed cables are HMWPE and older Crosslinked Polyethylene UG Residential Distribution cables installed from the early 1960s to around the mid-1980s. They are typically installed as a Cable-In-Conduit system or direct buried. These cables have exceeded, or are very close to, their 40-year average expected life.

The unjacketed cables comprise most cable failures in the system every year. Limited testing performed on these cables over the years has found significant concentric (neutral) wires deterioration in each area tested. The danger of failures of unjacketed cables with severely deteriorated concentric (neutral) is that the fault and normal (neutral) currents no longer have an intended path of flow, potentially causing failures on the circuit. These conditions then result in further deterioration of insulation of the cables, leading to increased failures on cables and other UG assets.

This program is considered as an alternative mitigation due to limited availability of funding, as well as this work having lower risk relative to Wildfire Risk.

TABLE 5-15
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR

			Thousands of Dollars				Millions of Dollars (NPV)[a]		
Line No.	Mitigation ID	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	DUNGD-A002	Radial Deteriorated Concentric Neutrals (Alternative Workplan)	$123,552	$247,104	$370,656	$494,208	$1,146.3	$30.3	<0.1
2		Total	$123,552	$247,104	$370,656	$494,208			

(a) NPV uses a base year of 2023.

Note: For additional details see Exhibit (PG&E-4), WP EO-DUNGD-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

Application: 24-05-
(U 39 G)
Exhibit No.: (PG&E-5)
Date: May 15, 2024
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT

EXHIBIT (PG&E-5)

ENERGY SUPPLY

PACIFIC GAS AND ELECTRIC COMPANY
2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
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RISK ASSESSMENT AND MITIGATION STRATEGY: LARGE UNCONTROLLED WATER RELEASE

A. Executive Summary

The Large Uncontrolled Water Release (LGUWR) risk represents the potential failure of a high- or significant-hazard dam, where failure of the dam could lead to *uncontrolled release*, resulting in potential loss of human life, economic loss, environmental damage, and other concerns. The four drivers considered for potential LGUWR events are (1) flood, (2) seismic, (3) failure under normal operating conditions,[1] and (4) physical attack. Seven PG&E enterprise cross-cutting factors[2] impact the LGUWR risk: (1) Climate Change, (2) Cyber Attack, (3) Emergency Preparedness and Response (EP&R), (4) Information Technology Asset Failure (ITAF), (5) Physical Attack, (6) Records and Information Management (RIM), and (7) Seismic.

Exposure to the LGUWR risk is derived from 60[3] dams in Pacific Gas and Electric Company's (PG&E or the Company) Corporate Risk Register (CRR) that are classified as high or significant hazard by the Federal Energy Regulatory Commission (FERC).[4]

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1 Formerly internal erosion.

2 PG&E's definition of a cross-cutting factor is a driver, component of a driver, or a consequence multiplier that impacts multiple risks across PG&E Enterprise Functional Areas.

3 PG&E's FERC reporting currently includes 63 high or significant hazard dams as classified by FERC. Three dams (Lower Peak, Lower Peak Auxiliary, and Kelly Lake Dams) were reclassified from low- to high-hazard dams in 2022 are not included in the LGUWR risk exposure because their flood hazard and life safety consequence analyses are still under development and were not available for inclusion in the 2024 bow tie model. Preliminary evaluations indicate potential life safety consequences of a dam breach for these three dams are relatively low compared with others in the model's scope.

4 The FERC hazard-potential classification is a system that categorizes dams according to the degree of adverse incremental consequences of a failure of a dam. The hazard-potential classification does not reflect in any way the current condition of the dam (e.g., safety, structural integrity, floor routing capacity). See FEMA, Federal Guidelines for Dam Safety, Hazard Potential Classification System for Dams (April 2004), available at: <https://www.ferc.gov/sites/default/files/2020-04/fema-333.pdf> (accessed May 1, 2024).

PG&E assigned one tranche for each of the 60 dams. While dams of similar types (e.g., earthfill dams or concrete arch dams) might have similar Potential Failure Modes (PFM), each dam is also unique because of its design, construction history, and site geology and can have unique site-specific PFMs. Allocating one tranche per dam allows PG&E to better capture dam-specific risk and risk reduction when pursuing mitigation projects for each unique dam.

The risk model indicates an annual probability of approximately 0.04 (1 in 25 years) that a LGUWR event will occur at one of the 60 dams included in the LGUWR risk exposure, based on expected conditions for the 2027 Test Year (TY) Baseline.[5] Potential risk events that result in life safety consequences have an estimated annual probability of 0.024 (1 in 42 years).

The Safety Risk Score for the LGUWR risk has the ninth-highest 2027 TY Baseline ($20.8 million per year) and the Total Risk Score for the LGUWR risk has the eighth-highest 2027 TY Baseline ($258.3 million per year) of PG&E's 32 CRR risks. The results of the risk modeling show that the flood driver accounts for approximately 51 percent, seismic accounts for approximately 37 percent, failure under normal operating conditions accounts for about 12 percent, and physical attack accounts for less than 0.1 percent of the calculated LGUWR risk. PG&E selected its planned mitigations for 2024-2030 to reduce risks from these key drivers.

PG&E proposes foundational activities, controls, and mitigations to reduce LGUWR risks. Based on the Risk Assessment and Mitigation Phase (RAMP) risk modeling results, PG&E expects the 2024 LGUWR baseline total adjusted risk of $288.8 million per year to improve by nine percent when the planned mitigations are completed in years 2024 to 2026, with a projected 2027 TY Baseline total-adjusted risk score of $258.3 million per year and 2030 post-mitigation total-adjusted risk score of $203.9 million per year. PG&E's mitigation efforts are categorized into one of the five programs. In the 2027 through 2030 General Rate Case (GRC) period, the spillway remediation program (LGUWR-M002) has the highest spend because of several large spillway and gates rehabilitation projects, followed by the internal erosion

5 The 2027 TY Baseline is in reference to the upcoming GRC cycle and reflects risk reduction from mitigation and control work performed through years 2024 to 2026.

program (LGUWR-M001), low-level outlet (LLO) refurbishment (LGUWR-M004), seismic retrofit for dams (LGUWR-M003), and physical security (LGUWR-M005). The aggregated cost-benefit ratio (CBR) for four out of the five programs is less than one. PG&E's risk mitigation strategies are selected to ensure that safety remains PG&E's top priority even when the quantitative RAMP modelling indicates the costs are higher than the modeled value of risk reduction (CBR<1). All five programs, regardless of their CBR, are essential to ensure the long-term safe and reliable operation of PG&E's dams.

Pit 3, Pit 5 Open Conduit (OC), Fordyce, Spaulding No. 1, and Belden Forebay Dams account for approximately 50 percent of 2027 TY Baseline total-adjusted risk score.

1. Risk Overview

The LGUWR risk represents the potential failure of a high- or significant-hazard dam (per FERC's hazard classification), where failure of the dam could lead to *uncontrolled release*, resulting in potential loss of human life, economic loss, environmental damage, and other concerns. Power Generation's (PG) dams are a critical component of PG&E's water storage and conveyance system. Out of the 165 total dams within the system, 60 dams are classified as high- or significant-hazard structures per FERC's hazard classification, have complete flood hazard and life safety consequence analyses, and are included in the LGUWR risk exposure. A summary of the LGUWR risk scope and definition is provided in Table 1-1.

PG&E's PG organization is responsible for managing the Company's portfolio of dams. PG, Dam Safety, and Asset Management teams, along with Operations and Maintenance (O&M) and Project Engineering departments, are responsible for identifying, managing, and mitigating dam safety risks to ensure the long-term safe and reliable operation of PG&E's dams.

TABLE 1-1
RISK DEFINITION, SCOPE, AND DATA SOURCES

Line No.	Risk Name	Large Uncontrolled Water Release
1	Definition	Failure of a high- or significant-hazard dam, where failure could cause loss of human life and/or could cause economic loss, environmental damage, and other concerns.
2	In Scope	The 60[(a)] dams designated as high or significant hazard, per the FERC hazard classification system.
3	Out of Scope	Non-FERC-jurisdictional dams, low-hazard dams, water conveyance facilities, powerhouses, and other hydroelectric assets. Although low-hazard dams are not included in LGUWR, PG&E inspects and maintains these dams.
4	Data Quantification Sources[(b)]	PG&E engineering evaluations and studies (such as dam stability analyses, seismic hazard analyses, flood hazard analyses, risk assessments, dam breach analyses), PG&E Emergency Action Plans, and ICOLD[(c)] (2019) database on dam failures.

(a) See Section B.1.d ("Tranches") for additional discussions on the selection of the 60 dams.
(b) Source documents will be provided with workpapers (WP) in May 2024.
(c) ICOLD, 2019, ICOLD incident database, Bulletin 99 update, *Statistical analysis of dam failures,* December 2019.

Key elements of PG&E's program for identifying, managing, and mitigating dam safety risks are summarized below:

- Foundational Activities:[6] To identify risks, PG's Dam Safety Program (DSP) and Dam Asset Management teams manage and implement foundational activities such as inspecting dams, performing engineering studies and evaluations, assessing risks, using instrumentation, and testing mechanical equipment and controls for spillway gates and LLOs. PG&E uses controls or mitigation measures to address maintenance issues and deficiencies that could affect dam safety. FERC and DSOD

6 The California Public Utilities Commission (CPUC) defines foundational activities as "Initiatives that support or enable two or more mitigation programs or two or more risks but do not directly reduce the consequences or reduce the likelihood of safety risk events." See D.21-11-009, Appendix D, available at: <https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M421/K075/421075369.PDF> (accessed May 1, 2024).

inspect PG&E's dams every one to three years, depending on hazard classifications, to confirm that PG&E's dams are well maintained.

- Controls:[7] O&M maintains the dams to ensure they are in good working condition. Maintenance activities include removing woody debris on or near spillways, repairing and patching deteriorated concrete, and managing vegetation.
- Mitigations:[8] Once DSP and Dam Asset Management identifies dam safety deficiencies that require mitigation measures to reduce risks, Project Engineering designs and implements mitigation projects. Examples of mitigation projects include seismically retrofitting dams and spillway rehabilitation.

Many capital mitigation projects for LGUWR take years to plan, design, secure regulatory permits, obtain agency review and authorization, and construct, sometimes beyond a decade. In the interim, PG&E employs short-term measures to reduce risk until the deficiencies can be mitigated. The short-term efforts are also called interim risk-reduction measures (IRRM), which can be foundational changes, controls, and/or mitigations. The scope of IRRMs is determined on a case-by-case basis and PG&E often works closely with key stakeholders for deficiencies requiring critical IRRMs. Throughout this chapter, examples are provided where such measures have been implemented to mitigate risk until the permanent solution is complete.

PG&E's water storage and conveyance systems consist of not only dams, but also reservoirs, tunnels, canals, flumes, siphons, and penstocks that enable PG&E to store and transport water from runoff and aquifer flows for PG at PG&E's hydro powerhouses. The conveyance and storage systems are operated to provide water storage and delivery for water

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7 The CPUC defines a control as a "Currently established measure that is modifying risk." See D.21-11-009, Appendix D, available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M421/K075/421075369.PDF (accessed May 1, 2024).

8 The CPUC defines a mitigation as a "Measure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event." See D.21-11-009, Appendix D, available at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M421/K075/421075369.PDF (accessed May 1, 2024).

conservation, fish and wildlife habitat protection and enhancement, domestic water usage, recreational requirements, and agricultural needs. PG&E's system consists of 150 reservoirs, 165 dams, 170 miles of canals, 43 miles of flumes, 126 miles of tunnels, 58 miles of pipe (penstocks, siphons, and low head pipes), 4 miles of natural waterways, and 140,000 acres of fee-owned land. PG is expanding its risk management program, including its risk register, to include other risks in its overall water storage and conveyance systems and better inform risk-based decision making across the organization. This expansion includes those risks accounting for failure of water conveyance systems. Some foundational activities and programs that are used to enable the control and mitigation of LGUWR and other risks are discussed in Section C.3, Foundational Activity, of this RAMP chapter and may be discussed further in PG&E's 2027 GRC filing. These activities and programs are a result of PG 's overall Asset Management System (AMS), which is also discussed in that section. However, this chapter will focus primarily on the risk management program's contributions to LGUWR.

B. Risk Assessment

1. Risk Bow Tie Methodology

The risk exposure includes the 60 PG&E dams that FERC classified as high or significant hazards and have complete analyses of their flood hazard and life safety consequences. Each of the 60 dams were assigned equal exposure to risk.

The LGUWR risk has four key risk drivers: (1) flood, (2) seismic, (3) failure under normal operating conditions (formerly internal erosion), and (4) physical attack. PG&E's CRR also includes seven cross-cutting factors that affect the LGUWR risk: (1) Climate Change, (2) Cyber Attack, (3) EP&R, (4) ITAF, (5) Physical Attack, (6) RIM, and (7) Seismic. Two of these cross-cutting factors, seismic and physical attack, are main drivers for LGUWR.

Risk outcomes are categorized as an uncontrolled release in an unpopulated area or an uncontrolled release in a populated area. In the former category, risk events typically do not result in loss of a human life and consequences or losses are primarily economic (losses borne by the public) and financial (losses borne by PG&E). The latter category includes potential loss of human lives.

In the 2020 RAMP, PG&E's LGUWR risk model incorporated PFMs related to extreme seismic, flood, and internal erosion events that resulted in full dam failure and focused on rare, extreme risk events that had significant consequences to the public and PG&E.

In the 2024 RAMP, to obtain a more complete risk picture for LGUWR, PG&E redefined the risk model to include other PFMs that could result in uncontrolled release caused by component damage, partial dam failure, or full dam failure. For example, the 2020 RAMP model included only global instability of an arch dam caused by seismic loading. The 2024 RAMP model can now incorporate other seismic-related PFMs such as seismic-induced instability of the rock abutment; internal instability of the arch dam resulting in failure of the upper section of the dam (i.e., partial failure); or damage of mechanical components that causes them to fail in an open position and results in an uncontrolled release.

Only 4 out of 60 dams incorporated full PFMs for the 2024 RAMP. PG&E developed the risks for these four dams using Semi-Quantitative Risk Assessment and in collaboration with FERC. Performing these risk assessments is labor and resource intensive for both PG&E and FERC; therefore, PG&E estimates that completing risk assessments for the remaining dams would take 10 to 15 years. PG&E will incorporate the results of these risk assessments into future LGUWR RAMP chapters as the risk assessments become available. In the meantime, PG&E's RAMP filing includes consideration of a subset of PFMs for the remaining dams, as explained more fully below.

PG&E used the Cost-Benefit Approach (CBA) to compute risk. The CBA involves assigning a monetary value to the safety and financial risk attributes. Detailed discussions on the CBA can be found in Exhibit (PG&E-2), Chapter 2, "Risk Modeling and Cost-Benefit Ratio."

a. Risk Drivers

The methodologies for the LGUWR risk drivers are described in the following sections:

1) D1 – Flood

Flooding typically occurs because of heavy rain, snowmelt, or a combination of rain or snow. PG&E actively manages flows from floods using weather forecasts, reservoir storage, and releases through spillways and outlets. PG&E also coordinates high-flow events with upstream and downstream dam operators.

In the 2020 RAMP, PG&E's LGUWR bow tie risk only considered extreme, large storms that resulted in overtopping and global instability of the dams. For the 2024 RAMP, PG&E's flood-driven PFMs have been expanded to include more frequent and smaller floods that could result in uncontrolled release from partial to full dam breach and failures of components such as spillway gates. The status of risk assessments for the flood driver is described below:

- PG&E completed FERC's risk assessments for four dams (Spaulding Nos. 1, 2, and 3, and Pit 3 Dams). These dams had a more complete set of flood-driver PFMs. Examples of new flood-driven PFMs for Spaulding Dams are internal instability of thrust block for Dam No. 1 resulting in partial dam failure, and progressive erosion of spillway channel leading to undermining and failure of the gated structure for Dam No. 2.
- PG&E completed focused risk assessments for nine dams with deficient spillways. These dams were Lake Almanor, Belden Forebay, Butt Valley, Philbrook, Round Valley, Cape Horn, North Battle Creek, Macumber, and Bucks Storage Dams. These nine dams had relatively complete PFMs for the flood driver. Examples of new PFMs include (1) overtopping of the spillway training wall from a more frequent flood that erodes the downstream embankment of the dam and results in dam breach and (2) damage to spillway slabs results in progressive erosion of the foundation that causes undermining and failure of the gate control structure.
- The remaining 47 dams only included consideration of extreme, flood-overtopping PFMs for the flood driver. Confidence of flood

driver estimates for these 47 dams was low because the flood hazard data was developed using rudimentary Log Pearson Type III extrapolations.

Inputs to Flood Driver

In the 2020 RAMP, flood inflow-frequency curves were developed using historical inflows (typically 50–80 years of data) and extrapolated for larger floods using the Log Pearson Type III method. This method is typically used for more frequent floods but is less reliable when extrapolated for estimating frequency of rarer and extreme flood events that PG&E's spillways can no longer safely pass. PG&E is currently updating flood frequency curves using more sophisticated precipitation and watershed modeling. These analyses included Stochastic Event Flood Model, United States Army Corps of Engineers (USACE) Rainfall Runoff Frequency Tool, and USACE Reservoir Frequency Analysis. To date, flood frequency curves have been completed for 15 dams and these results are included in the 2024 RAMP. These dams are Lake Almanor, Belden Forebay, Butt Valley, Philbrook, Round Valley, Cape Horn, North Battle Creek, Macumber, Bucks Storage, Spaulding Nos, 1, 2, and 3, Pit 3, Wishon, and Courtright Dams.

Likelihood of Failure for Flood

This section describes the programmatic approach for estimating likelihood of failure for the flood driver for the dams without FERC's risk assessments. The annual likelihood of failure for dams caused by flooding was computed by multiplying the annual probability exceedance of the critical flood by the probability of dam failure given the occurrence of the critical flood loads. The flood driver was assessed using different criteria for earthfill- and rockfill-embankment dams and for concrete gravity and arch dams. The section below provides more details on the computation for the annual likelihood of failure for flood for earth- and rockfill-embankment dams and concrete gravity and arch dams, respectively.

Earthfill- and Rockfill-Embankment Dams

Earthfill- and rockfill-embankment dams are vulnerable to overtopping flows because the materials at the crest of the embankment could be eroded, resulting in more flows going over the dam and eventually breaching the dam. PG&E conservatively assumed the critical flood occurs at the onset of overtopping. Earthfill embankment dams were assumed to fail at the onset of overtopping and were assigned a probability of dam failure at the critical flood load of 1.0. Rockfill embankment dams are slightly more resistant to overtopping; therefore, PG&E assigned a probability of dam failure at the critical flood load of 0.5 for fine-grained rockfill and a lower 0.25 probability for dams with larger sized rockfill in the downstream embankment.

PG&E notes that the design of spillway capacity for dams is traditionally, and still is, based on a deterministic criterion called the Inflow Design Flood[9] (IDF). For the purposes of risk assessments, PG&E considered floods that would result in overtopping of the embankment dams, and these floods could be larger than the IDF.

Concrete Gravity and Arch Dams

Concrete and gravity arch dams can generally handle more overtopping, especially if the dam has an overpour spillway and is designed to overtop. However, these dams can still be vulnerable at large overtopping flows if the abutments and downstream foundations were eroded, and the global stability of the dams were compromised. The flood driver for concrete dams was estimated using the largest flood that the dams can handle, based on available engineering stability analysis. The assigned probability of dam failure at the critical flood level ranged from 2 to 100 percent

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9 FERC, *Engineering Guidelines for the Evaluations of Hydropower Projects*, Chapter II, "Selecting and accommodating IDFs for dams," (August 2015). The determination of IDF is based on potential downstream consequences and is defined as the flood flow above which the incremental increase in water surface elevation due to failure of a dam or other water impounding structure is no longer considered to present an unacceptable threat to downstream life (human life) and property. The upper limit of flood magnitude for an IDF is the Probable Maximum Flood and the lower limit is typically the 100-year flood."

depending on susceptibility to foundation and abutment erosion and global stability of the dam.

2) D2 – Seismic

Many of PG&E's dams are located near known faults that have the potential to rupture and cause earthquakes. The ground motions caused by earthquakes could shake and damage PG&E's dams.

In the 2020 RAMP, PG&E's LGUWR bow tie risk considered PFMs that would result in a large global instability of the dam (large deformational failure for earthfill and rockfill embankment dams; sliding or overturning failure for concrete gravity and arch dams). For the 2024 RAMP, PG&E's seismic loading has been expanded to include any PFMs that could result in uncontrolled release from partial to full dam breach and component failures. As with the flood loading, only the four dams that have undergone FERC's risk assessments (Spaulding Nos 1, 2, and 3, and Pit 3 Dams) had more complete seismic-related PFMs. The remaining 56 dams only considered full global instability PFMs for seismic loading.

Inputs to Seismic Driver

The seismic hazard for the 2020 RAMP was based on PG&E's 2017 Deterministic Seismic Hazard Analysis (DSHA). In December 2021, PG&E updated its DSHA for all PG&E dams. PG&E's dams are required to meet the deterministic ground motion criteria, which is based on combination of FERC[10] and DSOD[11] seismic guidelines. As part of the 2021 DSHA updates, PG&E also developed Probabilistic Seismic Hazard Analysis (PSHA). Results from the PSHA can be used to estimate annual exceedance frequency of ground motion magnitude.

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10 FERC, Engineering Guidelines for the Evaluations of Hydropower Projects, Chapter 13, *Evaluation of Earthquake Ground Motions*, (May 30, 2018) seismic guidelines, Engineering Guidelines for the Evaluation of Hydropower Projects.

11 California Department of Water Resource's Division of Safety of Dams (DSOD), Divisions of Safety of Dams Inspection and Reevaluation Protocols, (Sept. 28, 2018).

Results of the 2021 DSHA indicated the ratio of the 2021 deterministic ground motions over the 2017 ground motions for spectral acceleration at 0.01 seconds ranged from an increase of 135 percent for certain dams to a reduction of 25 percent for others. In general, dams in PG&E's northern region (Shasta and DeSabla) saw the larger increase in ground motions while dams in the central and south regions (Drum, Mokelumne, and Southern areas) remained largely the same or saw some decrease.

Likelihood of Failure for Seismic

This section describes the programmatic approach to estimate likelihood of failure for the seismic driver for the 56 dams without FERC's risk assessments. The annual likelihood of failure caused by seismic load was computed by multiplying the annual probability exceedance of the seismic load with the probability of dam failure given the occurrence of the seismic loads. Seismic risks were assessed using different criteria for earthfill- and rockfill-embankment dams and for concrete gravity and arch dams, which are described below.

Earthfill- and Rockfill-Embankment Dams

Earthfill- and rockfill-embankment dams can deform under seismic loads, resulting in loss of dam crest elevation and overtopping failure. Seismic-induced deformation of the embankment was computed using seismic stability and deformational analysis. Ideally, the likelihood of failure should be estimated using the critical seismic load, but PG&E's existing seismic analyses only include ground motion for the deterministic design earthquakes, which are typically smaller than the critical load. For risk assessments, PG&E is estimating the annual likelihood of failure for seismic load based on available freeboard (distance between crest of the dam and reservoir elevation) following the deterministic seismic event. The dam is assigned a probability of failure of 1.0 if no freeboard is available after the earthquake and 0.02 to 0.5 depending on the available freeboard and if the dam has crack stopper that helps to minimize the potential for transverse cracking.

Concrete Gravity and Arch Dams

The PFM for concrete gravity dams considered for this risk assessment is failure by sliding or overturning. Using the ground motion of record, a probability of failure for the given earthquake ranged from 2 percent (for factors of safety greater than 1.5) to 100 percent (safety factor of one or less). For concrete arch dams, structural demand over capacity ratio was used to estimate the probability of failure. The probability of failure for the given earthquake ranged from 2 to 100 percent, depending on the magnitude of the demand over capacity ratio.

3) D3 – Failure under Normal Operation Conditions

Dams can fail under normal operating conditions. In the 2020 RAMP, the failure under normal operation conditions was called "internal erosion" and the PFM was limited to internal erosion PFMs for earthfill- and rockfill-embankment dams. In the 2024 RAMP, the definition of failure under normal operation conditions was expanded to include all PFMs that could result in uncontrolled release during day-to-day operations, in the absence of large seismic and flood loads. PFMs can include the following examples:

- Failure of components such as spillway gates or LLO values that cause the component to be stuck in an open position and result in an uncontrolled release;
- Initiation and progression of internal erosion of earthfill- and rockfill-embankment dams that lead to dam breach; and
- Initiation and progression of internal erosion of foundation material beneath the dams or in the abutments, resulting in uncontrolled release or dam breach.

Likelihood of Failure under Normal Operations

In the 2020 RAMP, the internal erosion driver was developed for 41 earthfill- and rockfill-embankment dams. For the 2024 RAMP, the internal erosion PFM is retained as the risk driver for failure under normal operations, except for Spaulding No. 3 dam that had a completed FERC risk assessment.

Because there are currently no industry-accepted methodologies for calculating annual likelihood of failure for internal erosion, PG&E used an industry data set from ICOLD (2019) to guide the estimation of annual likelihood of failure for PG&E's dams. The database contained worldwide data with a total of 33,470 dams and cumulative total-dam years of approximately 1.8 million years. There were 81 cases of dam failures caused by internal erosion for earthfill dams and the annualized frequency of exceedance was calculated as approximately 4.5 in 100,000 years. There were 5 cases of failures for rockfill dams and the annualized frequency of exceedance was 2.76 in 1,000,000 years, which was rounded to 3 in 1,000,000 years. PG&E also used the Foster[12] (1998) database to help guide risk estimates for type of embankment dams. As indicated in the Foster (1998) paper, homogenous earthfill dams are most susceptible to internal erosion and the annual likelihood of failure was reduced by a factor of five if the dam has filter or has a corewall. The probability of failure for PG&E dams is adjusted from the baseline annual exceedance of failure of 4.5 in 100,000 years based on whether the dam is homogenous, has filter, is zoned, or has core-wall for minimized seepage through the dams.

After the completion of FERC risk assessments for the four dams (Spaulding Nos 1, 2, and 3; Pit 3 Dams), new PFMs for failure under normal operation conditions were added to the bow tie. Examples of new PFMs resulting in uncontrolled release include failure of abutments rock block for an arch dam under normal conditions, concentrated leak in the dam foundation and abutments, and LLO ruptures.

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12 Foster, Fell, Spannagle, *Analysis of Embankment Dam Incidents*, (Sept. 1998), University of New South Wales.

4) D4 – Physical attack

Physical attack is defined as threats from third-party individuals such as break-ins, vandalism, and attack that could result in a dam failure. PG&E has a security program to plan and mitigate potential physical attacks on the dam assets. This program complies with FERC guidance.

There were no instances of a dam failure driven by physical attack in the United States, although one incident of the use of an improvised explosive device was recorded on an access road near Black Rock Dam in Connecticut.[13] The dam was not damaged. Using the physical attack incident data from the Department of Homeland Security, ASDSO database[14] for the number of dams in the United States, and an assumption that the next dam attacked would result in dam failure, the probability of a physical attack on a dam was estimated as 5.9 in a million. The probability of dam failure given the physical attack is assumed to be 3.8 percent.

b. Cross-Cutting Factors

Cross-cutting factors are drivers, a component of a driver, or a consequence multiplier that impacts multiple risks across PG&E Enterprise functional areas. Seven PG&E enterprise cross-cutting factors affect the LGUWR risk, five of which are explicitly quantified: (1) EP&R, (2) ITAF, (3) Physical Attack, (4) RIM, and (5) Seismic. The cross-cutting factors that impact LGUWR are shown in Table 1-2 below. A description of the cross-cutting factors and the mitigations and controls that PG&E is proposing to mitigate the cross-cutting factors is in Exhibit (PG&E-2), Chapter 3, "Cross-Cutting Factors."

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[13] Department of Homeland Security, *Worldwide Attacks Against Dams: A Historical Threat Resource for Owners and Operators* (2012), available at: https://damfailures.org/wp-content/uploads/2019/04/Worldwide-Attacks-Against-Dams.pdf (accessed May 1, 2024).

[14] Association of State Dam Safety Officials (ASDSO) *Dam Safety Incident Database,* available at: https://damsafety.org/incidents (accessed May 1, 2024).

TABLE 1-2
CROSS-CUTTING FACTORS SUMMARY

Line No.	Cross-Cutting Factor	Impacts Likelihood	Impacts Consequence
1	Climate Change	Yes*	No
2	Cyber Attack	Yes*	No
3	EP&R	No	Yes
4	ITAF	Yes	No
5	Physical Attack	Yes	No
6	RIM	No	Yes
7	Seismic	Yes	No

Yes The cross-cutting factor has been quantified in the model.

Yes* The cross-cutting factor does influence the baseline risk but has not been quantified in the model, or the cross-cutting factor may influence the baseline risk but further study is needed.

No The cross-cutting factor does not meaningfully influence the baseline risk.

The following list provides details on the methodologies for cross-cutting factors:

1) **CC1 – Climate Change**

PG&E designated climate change as an enterprise risk in 2017. PG&E enterprise identified five primary climate-driven contributors to risk: (1) change in temperature extremes, (2) flooding and precipitation, (3) sea level rise, (4) wildfire, and (5) drought-driven land subsidence.

Of the five primary climate-driven contributors to risk, the wildfire contributor could impact the likelihood of LGUWR in the short term. While dams are generally resilient to wildfires, a large wildfire near reservoirs and dams could damage trees and increase the potential for woody debris entering the reservoir during winter storms and block the spillways. Ancilary structures such as supervisory control and data acquisition (SCADA) communication towers and control buildings could be susceptible to direct wildfire damage. Based on PG&E's preliminary review, PG&E believes the risk from wildfire can be managed by removing dead trees around the reservoir rim following a large wildfire and immediately repairing damaged ancillary structures.

The change in precipitation patterns contributor could impact LGUWR in the long term. The long-term changes in precipitation were projected to result in an average drier climate, with more extreme wet storms and drought, by 2050. The long-term average drier climate is not expected to increase flood risk for PG&E's dams. However, if a wettest of the high-emission climate change scenario is considered (i.e., 90th percentile of the precipitation for Representative Concentration Pathway (RCP) 8.5), the extreme wet storms could potentially increase the likelihood of dam overtopping by 2050. In the near term between years 2024 to 2030, PG&E does not anticipate changes in precipitation patterns to significantly impact the flood driver because spillways for the high-hazard dams are designed for more extreme floods.

2) CC2 – Cyber Attack

A cyber-attack risk is defined as a coordinated, malicious attack targeting PG&E's core business functions. A deliberate cyber-attack that results in a breach to PG&E's cybersecurity can lead to loss of critical instrumentation, communication infrastructure, and loss of control to remotely operated flow-control structures. A cyber-attack that coincides with conditions that can cause a dam failure (flood, seismic, failure under normal conditions, and physical attack) can increase the likelihood that a catastrophic outcome will occur. PG&E is currently refining the methodology and the risk for Cyber Attack is not included at this time.

3) CC3 – Emergency Preparedness and Response

The Emergency Preparedness and Response (EP&R) cross-cutting factor represents PG&E's capability to plan and respond to emergencies that could significantly impact public safety and the reliability of PG&E's assets. Issuance of LGUWR emergency warnings range from high-flow notifications to warnings for immediate evacuation because of imminent dam failure.

When responding to emergencies, the EP&R team (consisting of EP&R Strategy and Execution, Hazard Awareness & Warning

Center (HAWC), and the Geosciences team) works closely with PG's emergency response team and external operations centers (such as California Governor's Office of Emergency Services Warning Center and California Department of Water Resources Flood Operations Centers), emergency responders (such as local sheriff and California Highway Patrol), and regulators. PG&E conducts annual trainings and exercises with these emergency responder partners. PG&E's Emergency Action Plans (EAP) team is responsible for conducting these trainings, maintaining relationships with emergency responders, and updating the EAP documents.

The EP&R cross-cutting factor impacts the safety consequence because a more effective emergency response effort can reduce potential fatalities resulting from a dam failure incident. For LGUWR, issuance of emergency warning and response was incorporated into the computation for fatalities using the Dekay-McClelland empirical method[15] and newer Reclamation's Life Loss Estimating Methodology (RCEM) and LifeSIM consequence modeling. PG&E did not compute an alternate risk if EP&R measures were not implemented.

4) CC4 – ITAF

Information Technology (IT) services, hardware, and software assets are critical to safe operations of PG&E's dams. IT assets are used to support PG&E's day-to-day operations, monitoring, asset management, and emergency response.

The ITAF cross-cutting factor is defined as a failure of an IT asset that coincides with another driver and increases the likelihood of a catastrophic outcome. ITAF was added as a multiplier to the four drivers (D1 through D4).

PG&E's goal for availability of the critical IT infrastructure is 99.9 percent. PG&E estimated that the probability of the IT

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15 Dekay, Michael L., and McClelland, Gary H., *Predicting Loss of Life in Cases of Dam Failure and Flash Floods,* Risk Analysis, (Apr. 1993).

infrastructure and communication system not being available is 4.8 percent.[16] The likelihood of failure was assumed to increase by 50 percent if ITAF occurred at the same time as a major driver causing catastrophic dam failure.

5) CC5 – Physical Attack

See description for physical attack risk driver in Section D4, "Physical Attack."

6) CC6 – RIM

The RIM cross-cutting factor refers to how well PG&E stores and retrieves important dam safety documentation to maintain a safe, operating system. Good RIM can reduce the likelihood of an operational incident by making it easy to locate needed records in a timely fashion. The value of RIM ineffectiveness was taken as 2 percent and added as a multiplier to the financial consequences.

7) CC7 – Seismic

See discussion in chapter D2 Seismic driver above. Seismic was a cross-cutting factor for PG&E's other functional areas but is one of the four drivers for the LGUWR risk.

c. Outcomes and Consequences

The LGUWR risk has two outcomes: (1) O1 – uncontrolled release in unpopulated areas; and (2) O2 – uncontrolled release in populated areas.

The O1 outcome was typically used for smaller component failures and partial dam failures where the incremental uncontrolled release was not expected to result in human fatalities and the consequences were primarily financial. The O2 outcome could result in potential human fatalities in areas with permanent buildings and campgrounds.

The LGUWR risk consequences are Safety and Financial as described below:

16 See Exhibit (PG&E 2), WP RM-CCF, IT-ITAFL_LGUWR for more information.

Safety

Safety consequences for the LGUWR risk are potential fatalities and injuries when incremental uncontrolled release from dams impact population centers or recreational areas.

PG&E developed inundation maps for full dam breach during the IDF and fair-weather (FW) conditions. For dams with larger spillway control structures, PG&E also developed inundation maps for failure of these control structures during a FW scenario. Cascading impacts of downstream dam failures were included in the dam breach analyses—if a downstream dam was determined to breach, its reservoir volume was added to the total breached flow.

For the 2020 RAMP, PG&E estimated potential fatalities for IDF and FW scenarios using the Dekay-McClelland empirical method.[17] Population-at-Risk (PAR) was determined by counting the number of structures within the inundation zone from the flood maps for each dam and estimating one person per structure. Fatality was estimated from the PAR based on warning time and force of water on the structures. Injuries were estimated by applying a ratio of 1.87 injuries per fatality to the estimated fatality. This ratio is not part of Dekay-McClelland empirical method and was taken from the National Oceanic and Atmospheric Administration flood data for California. The equivalent total fatalities was used for safety consequences and calculated by summing the total fatalities and one quarter of total injuries. Transient population (e.g., recreational population) was not considered.

PG&E is currently updating the safety and economic consequences using newer methodologies such as United States Bureau of Reclamation's RCEM or USACE LifeSIM model to obtain more reliable consequence values. For information on location and type of structures, occupancy, and estimated property value (structure replacement costs, vehicles, and value of contents within the structure), PG&E used data provided by the USACE's National Structure Inventory (NSI) database.

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17 Dekay, Michael L., and McClelland, Gary H., *Predicting Loss of Life in Cases of Dam Failure and Flash Floods,* Risk Analysis, (Apr. 1993).

Transient population is now included in the safety consequences and transient PAR were estimated by identifying locations of recreational areas and occupancy from their websites. PG&E's issuance of warning time, which is the time to detect an issue, verify, and issue evacuation warnings, are included when determining potential fatalities. Injuries were also applied at a ratio of 1.87 injuries per fatality to the estimated fatalities and equivalent total fatalities were used for safety consequences. For the 2024 RAMP, PG&E updated safety and economic consequences for 13 dams. These are the four dams that completed FERC's risk assessments and the nine dams with focused spillway risk assessments (see D1 – Flood Loading under Section 1.1 for names of dams). PG&E anticipates requiring approximately five years to update the consequence models for the remaining 47 dams using new methodologies.

As part of the CBA approach, the equivalent total fatalities were monetized by using a California-adjusted Value of a Statistical Life of 15 million dollars per life loss for year 2022. Further details can be found in Section 6.a of Exhibit (PG&E-2), Chapter 2, "Risk Modeling and Cost-Benefit Ratio."

Uncertainties for safety consequences were modeled using a Poisson-Bernoulli distribution with a standard deviation of 0.3.

Financial

Financial consequences included in the LGUWR risk are direct economic damage to the public, cost of replacement for PG&E's dams and powerhouses, and foregone revenue from loss of generation.

In the 2020 RAMP, PG&E computed direct economic damage to the public by using average home prices, number of structures damaged, and infrastructure factors. For residential and commercial buildings, PG&E assumed full structure damage and replacement costs (using average home prices) if structures were inundated within 30 minutes of the dam breach and partial damage (50 percent of average home prices) if time to inundation was more than 30 minutes. To account for general damage to infrastructure such as roads, powerlines, and other infrastructure, PG&E assumed the cost of damage to infrastructure to be equal to the total damage to residential and commercial buildings.

PG&E's internal financial costs consisted of cost of replacement for PG&E's dams and powerhouses, and foregone revenue from loss of generation. The dam restoration costs were estimated by using dam size and type and reservoir size. The foregone revenue from loss of generation was based on PG&E's pricing model for generation of hydropower and included pricing on energy revenue (direct revenue from generation of energy), Resource Adequacy (value provided by hydroelectric as a standby resource during peak load days), Renewable Energy Credits, and Ancillary Services revenue. PG&E notes that replacement costs for cascading failure of dams were not included in the 2020 RAMP and loss of revenue generation was assumed to be one year.

For the 2024 RAMP, PG&E included the replacement costs for cascading failures of dams and powerhouses. The duration for loss of revenue generation for full dam breach was assumed to be 10 years, which included the time for environmental clean-up, design, permitting, and construction of new dams and powerhouses. The cost of foregone revenue from loss of generation was computed using a price forecast developed in 2023. For the four dams with FERC risk assessments and nine spillways with focused spillway risk assessments, the direct economic damages to residential and commercial buildings were computed using information from USACE NSI database.

Uncertainties for safety consequences was modeled using a normal- distribution with standard deviation of 0.1.

d. Tranches

PG&E assigned one tranche for each of the 60 dams. The benefit of allocating one tranche per dam allows PG&E to better capture dam-specific risks and risk reductions when pursuing mitigation projects for each unique dam.

In 2020, PG&E had a total of 61 high- or significant-hazard dams included in RAMP and these dams were classified using FERC's hazard classification. Since then, PG&E has sold one dam (Chili Bar Dam).

PG&E's FERC reporting currently includes 63 high or significant hazard dams as classified by FERC. Three dams (Lower Peak, Lower Peak Auxiliary, and Kelly Lake Dams) were reclassified from low- to high-hazard in 2022 are not included in the LGUWR risk exposure because their flood hazard and life safety consequence analyses are still under development and were not available for inclusion in the 2024 bow tie model. Preliminary evaluations indicate potential life safety consequences of a dam breach for these three dams are relatively low compared with others in the model's scope. The 2024 LGUWR risk register contained 60 high or significant hazard dams with complete flood hazard and life safety consequence analyses. PG&E continues to inspect and maintain all 165 dams regardless of classification.

A list of the 60 dams, FERC classifications, dam type and location is included in supporting workpapers.[18]

2. Risk Results

a. LGUWR Bow Tie

PG&E's total, adjusted-risk[19] for the LGUWR risk 2027 TY Baseline is shown in Figure 1-1. The bow tie shows aggregated risk scores from all 60 dam tranches, risk drivers, and outcomes. The annualized total, adjusted-risk for the 2027 TY Baseline is $258.3 million per year, out of which $20.8 million per year was the safety risk and $237.5 million per year was the financial risk.

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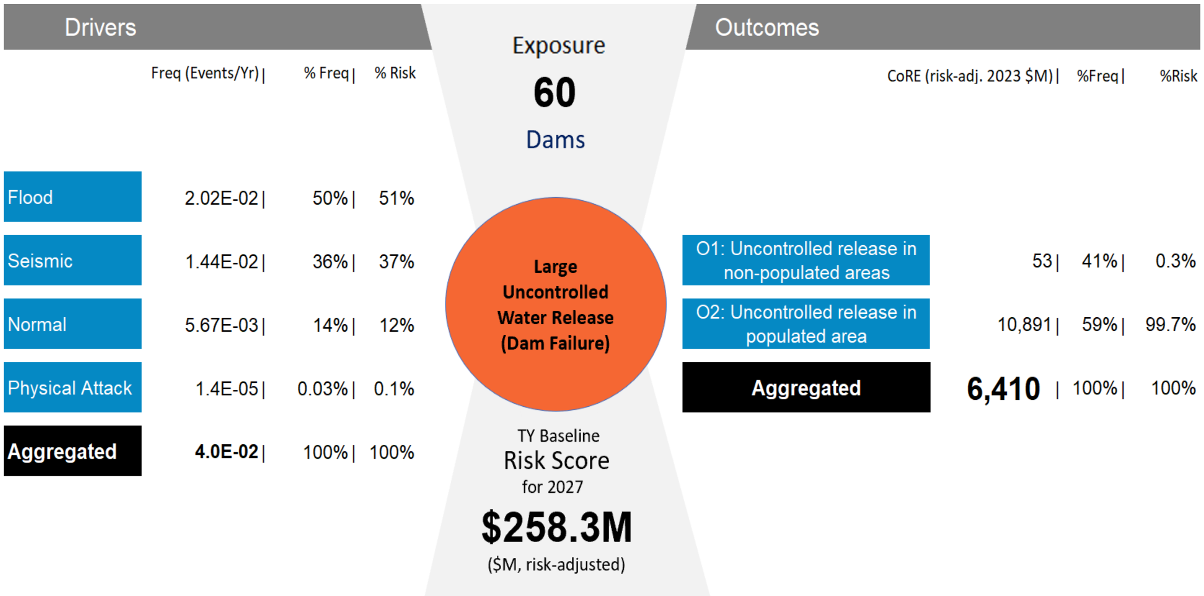
18 See Exhibit (PG&E-5), WP GEN-LGUWR-06_Tranche Selection.

19 Adjusted-risk means the risk score includes adjustments for PG&E's non-linear risk attitude.

FIGURE 1-1
TOTAL ADJUSTED-RISK SCORE FOR 2027 TY BASELINE



1) Difference from 2020 Risk Bow Tie

PG&E's bow tie methodology was significantly changed in the 2024 RAMP because the 2024 RAMP used a CBA and the 2020 RAMP used a Multi-Attribute Value Function approach. Consequently, a direct comparison between the 2020 RAMP and 2024 RAMP was not possible.

Flood was still a major driver for the 2024 RAMP, though the proportion of the seismic driver had increased to 37 percent from 6 percent in 2020. The increase in the likelihood of failure from the seismic driver was a combination of increase in ground motion following the 2021 seismic hazard update, refinement in the criteria for evaluating seismic risk, and expansion of seismic loading to include any PFMs that could result in uncontrolled release from partial to full dam breach and component failures as described in the previous seismic risk methodology section. As with the flood loading, only the four dams that have undergone FERC's risk assessments.

PG&E believes the total risk for the 2024 RAMP has increased from the 2020 RAMP because of the scope change for LGUWR (i.e., inclusion of more PFMs that could result in uncontrolled release) and changes in financial consequences (i.e., dam replacement costs for cascading failure were included and foregone revenue caused by full dam breach was increased from 1 year to 10 years). The increase is believed to be a result of the maturation in quantification of the risk and not deficiencies in PG&E's ability to respond to risk.

2) Exposure to Risk

Each of the 60 dams have equal exposure to risk (i.e., exposure of 1/60 for each dam).

3) Tranches

Table 1-3 shows a list of top 10 dams (or tranches) ranked based on total adjusted-risk score for the 2027 TY Baseline. The risk for the rest of the 50 dams were aggregated and shown as "all remaining dams." The top five dams, which were Pit 3, Pit 5 OC, Fordyce, Spaulding No. 1, and Belden Forebay Dams, constituted nearly half of the total adjusted-risk for LGUWR. The section below provides additional discussion and detail for the five dams:

- Pit 3 Dam has the highest total adjusted-risk. PG&E completed a FERC risk assessment for Pit 3 Dam in 2023. Key risk drivers at Pit 3 Dam were PFMs related to the global stability of the dam under flood and seismic loading. However, the confidence level for the risk estimates related to global stability of the dam was low because the subject matter experts believed a parameter used in the global stability analysis was too high, resulting in more favorable safety factors. PG&E plans to perform additional foundational studies (geology review and, if needed, geotechnical investigations and additional stability analyses) to better define this parameter. Results of these foundational studies will be used to re-estimate the risks and determine if additional risk reduction measures are needed.
- Pit 5 OC Dam is ranked second and the main risk driver is seismic. Results of the updated 2021 Deterministic Seismic Hazards Results (DSHR) indicated ground motion levels have

increased for this dam. PG&E is in the process of updating the seismic stability analysis for Pit 5 OC. Results of this analysis will be used to determine if the dam can meet the deterministic design earthquake load and, if needed, potential risk reduction measures.

- Fordyce Dam is ranked third. Key risk drivers at Fordyce are seismic and flood but confidence levels for these risks estimates were low. PG&E is performing seismic stability and deformation analysis (foundational studies) to better characterize seismic driver for the dam. In fall of 2024, PG&E is also performing spillway-focused risk assessment (foundational studies) to better understand risk associated with the undersized and deficient spillway.
- Spaulding No. 1 Dam is ranked fourth. PG&E completed a FERC risk assessment in 2023. Key risk drivers are PFMs related to internal and external stability of the dam and abutments for flood and seismic drivers but confidence for these risk estimates was low. PG&E is still evaluating next steps that may include additional foundational studies to improve confidence of the risk estimates.
- Belden Forebay Dam is ranked fifth. Flood is the main risk driver at Belden Forebay Dam because the spillway is structurally deficient and undersized. PG&E has initiated a project to retrofit the spillway.

TABLE 1-3
TRANCHE LEVEL RISK ANALYSIS RESULTS, SORTED BY TOTAL ADJUSTED-RISK

Line No	Tranche	Percent Exposure	Safety Adj-Risk Score ($M/year)	Financial Adj-Risk Score ($M/year)	Total Adj-Risk Score ($M/year)	Percent of Total Risk
1	Pit 3	1.67%	1.85	37.4	39.2	15%
2	Pit 5 Open Conduit	1.67%	1.38	26.1	27.5	11%
3	Fordyce	1.67%	0.78	21.6	22.3	9%
4	Spaulding No. 1	1.67%	7.35	13.3	20.6	8%
5	Belden Forebay	1.67%	0.03	17.9	17.9	7%
6	Lake Almanor	1.67%	0.18	17.3	17.4	7%
7	Rock Creek (Feather)	1.67%	0.42	14.1	14.5	6%
8	Salt Springs	1.67%	0.52	13.8	14.4	6%
9	Pit 4	1.67%	0.01	13.3	13.3	5%
10	Iron Canyon	1.67%	0.05	10.8	10.9	4%
11	All remaining dams	83.3%	8.2	52.0	60.3	23%
12	Total	100%	20.8	237.5	258.3	100%

4) Drivers and Associated Frequency

PG&E identified five drivers for the LGUWR risk. Each driver and its associated 2027 TY Baseline frequency is discussed below.

a) D1 – Flood

The flood driver constituted approximately 51 percent of the risk drivers for LGUWR. The aggregated flood driver could result in an incident leading to uncontrolled release once every 50 years, although this frequency reduced to 1 to 85 years if only outcome O2 (uncontrolled release in populated areas) was considered. For comparison, the flood driver for the 2020 RAMP could result in a catastrophic dam failure event once every 77 years.

b) D2 – Seismic

The seismic driver constituted approximately 37 percent of the risk drivers for LGUWR. The aggregated seismic driver could result in an incident leading to uncontrolled release once every 69 years, or 1 in 95 years if only outcome O2 (uncontrolled release in populated areas) was considered. For comparison, the seismic driver for the 2020 RAMP could result in a catastrophic dam failure event once every 714 years.

c) D3 – Failure Under Normal Operating Conditions

Uncontrolled release caused by failure under normal operating conditions constituted 12 percent of the drivers for LGUWR. The aggregate driver could result in an incident leading to uncontrolled release once every 176 years, or 1 in 737 years if only outcome O2 was considered. This D3 driver was previously called internal erosion in the 2020 RAMP and its scope were limited to 41 earthfill and rockfill embankment dams. The 2020 RAMP aggregate frequency for a catastrophic dam failure incident was once every 1,667 years.

d) D4 – Physical Attack

Physical Attack events accounted for 0.1 percent of the total adjusted-risk. The aggregate frequency for a catastrophic dam failure is approximately once every 73,700 years. This risk is similar to the 2020 RAMP results.

e) CC4 – ITAF

Total frequency for ITAF was computed as 0.0012 (or event happening 1 in 837 years). The total adjusted-risk attributed for ITAF is $17.6 million per year, or approximately 7 percent of the total adjusted-risk.

f) CC6 – RIM

The RIM cross-cutting factor is included as a multiplier of 2 percent to the financial consequences of $237.5 million per year. The estimated total adjusted-risk for RIM is approximately $4.7 million per year, or 1.8 percent of the total adjusted-risk.

5) Consequences

a) Aggregated Consequences

Consequences of this risk event are shown in Table 1-4 below. Model attributes are described in Exhibit (PG&E-2), Chapter 2, “Risk Modeling and Cost-Benefit Ratio.”

The aggregated O1 (uncontrolled release in non-populated areas) outcome constitutes 41 percent of the total frequency, but only 0.3 percent of the risk. The PFMs resulting in O1 outcome were primarily component damage or partial dam failures that had higher likelihood of occurrence and more limited uncontrolled release. The aggregated frequency indicated that an incident resulting in the O1 outcome may occur approximately once every 60 years. The aggregated O2 (uncontrolled release in populated area) outcome constitutes 59 percent of the frequency and 99.7 percent of the total risk. The aggregated frequency indicated an incident resulting in the O2 outcome may occur approximately once every 42 years. The frequency for the combined O1 and O2 outcomes indicated an incident resulting in either outcome may occur approximately once every 25 years.

TABLE 1-4
RISK EVENT CONSEQUENCES FOR TEST-YEAR 2027

Consequences

					Natural Units Per Event		Monetized Levels ($M) of a Consequence Per Event		CoRE (risk-adjusted, $M)		Natural Units per Year		Expected Loss per Year ($M)		Attribute Risk Score (risk-adjusted, $M)	
	CoRE |	%Freq |	%Risk	Freq	Safety EF/event	Financial $M/event	Safety $M	Financial $M	Safety	Financial	Safety EF/yr	Financial $M/yr	Safety $M/yr	Financial $M/yr	Safety	Financial
O1: Uncontrolled release in non-populated areas	53 |	41% |	0.3%	1.7E-02	-	30.9	-	30.9	-	53.2	-	0.5	-	0.5	-	0.9
O2 - Uncontrolled release in populated areas	10,891 |	59% |	99.7%	2.36E-02	11.4	1,673.0	143.0	1,673.0	880.0	10,010.5	0.3	39.5	3.4	39.5	20.8	236.6
Aggregated	6,410 |	100%	100%	4.03E-02	6.7	994.2	83.9	994.2	516.2	5,893.9	0.3	40.1	3.4	40.1	20.8	237.5

b. Climate Adaptation Vulnerability Assessment Results

PG&E designed the Climate Adaptation Vulnerability Assessment (CAVA) to be consistent with the CPUC's Final Ruling on Order Instituting Rulemaking to Consider Strategies and Guidance for Climate Change Adaptation (Rulemaking 18-04-019). The methodology outlined by Decision (D.) 20-08-046 required utilities to perform an assessment of all assets, operations and services that will be impacted by future risks from climate change related to changes in temperatures, precipitation and flooding, sea level rise, wildfire, and drought driven subsidence.

PG&E's CAVA addresses actual or expected climatic impacts on the Hydro Generation assets, with a focus on the 2050 decadal time period. The CAVA assessment on PG&E's Hydro Generation Assets considered impacts to utility planning, facilities maintenance and construction, and communications, to maintain safe, reliable, affordable, and resilient operations.[20] The CAVA results consider all Hydro Generation assets, including the Company's dam's and powerhouse assets.

The CAVA climate risk findings consider generalized impacts from future climate hazards to all hydro generations assets that could have significant consequences for customers, public safety, and the environment. Given the differences in exposure, sensitivity, vulnerability between dams and other types of hydroelectric assets, PG&E's CAVA at times provides a separate climate risk ranking when these asset types diverge significantly.

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[20] PG&E's Climate Adaptation Vulnerability Assessment, Section 3.1.3.a Hydropower Generation (to be published May 15, 2024).

TABLE 1-5
LGUWR: CAVA CLIMATE RISK SCORES

Line No.	Climate Hazard	Adaptive Capacity	Climate Change Risk
1	Temperature	High	Low (off-ramped)
2	Flooding/ Precipitation	Low to Moderate	High (Moderate for FERC high or significant hazard dams)
3	Sea Level Rise	Not Assessed	Not Assessed
4	Wildfire	Moderate	High
5	Drought-driven subsidence	Not Assessed	Not Assessed

The adaptive capacity of PG&E's hydro generation assets to future climate hazards was a key factor in determining the Company's climate risk rankings. Adaptive capacity was defined as the ability of an asset or system to moderate or eliminate identified climate vulnerabilities as assessed based on 2050 conditions and mitigate future impacts. This included any aspect of design, planning, operations, monitoring, emergency response capacities, and other PG&E capabilities. As described in PG&E's CAVA, Hydroelectric assets have high adaptive capacity to address climate risks associated with temperatures. Adaptive capacity for wildfire was rated as moderate for hydroelectric assets and low to moderate for flooding/precipitation climate hazards. No adaptive capacity or climate risk rankings were provided for sea level rise or drought-driven subsidence since hydroelectric assets are not exposed to those climate hazards.

c. Potential Environmental and Social Justice Consequences

Environmental and Social Justice (ESJ) is defined as "fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies."[21] For RAMP 2024, ESJ for LGUWR is included as a pilot study. The scope of this ESJ pilot effort was to identify which communities could be impacted by potential

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21 CPUC, ESJ website, available at: <https://www.cpuc.ca.gov/ESJactionplan/> (accessed May 1, 2024).

dam breach. Results of this study were not used when planning controls and mitigation measures.

Dam breach inundation maps for flood and FW conditions for high or significant hazard dams were overlayed with the ESJ map[22] to visually identify potential impacts of dam breach to disadvantaged and vulnerable communities (DVCs, as defined in D.22-12-027). If the inundation zone caused by dam breach was found to overlap areas containing DVC, the dam was considered to impact DVC. The total cost for mitigations and controls, along with the estimated risk reductions were calculated by including all mitigation and control projects for dams that were identified to impact DVC.

PG&E identified 19 dams that have the potential to impact DVCs. These dams are listed below, along with the total spend for mitigations and controls, and risk reductions for years 2027 through 2030. In total, PG&E expects to spend $36.8 million in expense and $1,065 million in capital on risk reduction for LGUWR, of those totals $7.5 million in expense and $288.4 million in capital will be spent on dams that affect DVC.

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[22] California Office of Environmental Health Hazard Assessment (OEHHA), Senate Bill (SB) 535 Disadvantaged Communities map, available at: (https://oehha.ca.gov/calenviroscreen/sb535 (accessed May 1, 2024).

TABLE 1-6
DAMS THAT COULD IMPACT DVC DURING HYPOTHETICAL DAM BREACH SCENARIOS
(MILLIONS OF DOLLARS, 2023)

Line No.	Dam	ESJ Areas within Inundation Zone	Tribal Lands Areas within Inundation Zone	2027-2030 Program Risk Reduction Net Present Value (NPV)	2027-2030 Capital Cost NPV	2027-2030 Expense Cost NPV	2027-2030 Total Cost NPV
1	Bear, Lower	Yes	No	$0.68	$6.76	$0.39	$7.15
2	Bear, Lower No. 2	Yes	No	$0.45	$6.76	$0.39	$7.15
3	Bear, Upper	Yes	No	$0.79	$6.76	$0.39	$7.15
4	Bucks Lake	Yes	No	$11.33	$11.49	$0.31	$11.80
5	Crane Valley	No	Yes	$7.42	$8.44	$0.39	$8.82
6	Fordyce	Yes	No	$73.58	$17.72	$0.39	$18.11
7	Lake Almanor	Yes	No	$15.98	$29.37	$0.31	$29.69
8	Pit 1 Forebay	No	Yes	$0.17	$7.61	$0.39	$8.00
9	Pit 3	No	Yes	$15.86	$17.08	$0.39	$17.47
10	Pit 4	No	Yes	$12.45	$8.41	$0.39	$8.79
11	Pit 5 Open Conduit	No	Yes	$5.98	$8.77	$0.39	$9.15
12	Pit 6	No	Yes	$86.49	$40.17	$0.77	$40.94
13	Pit 7	No	Yes	$59.93	$32.62	$0.39	$33.01
14	Relief	Yes	No	$16.49	$31.12	$0.39	$31.51
15	Salt Springs	Yes	No	$10.85	$6.81	$0.39	$7.20
16	Scott	No	Yes	$0.31	$5.37	$0.39	$5.76
17	Spaulding No. 1	Yes	No	$78.98	$19.83	$0.31	$20.14
18	Spaulding No. 2	Yes	No	$53.19	$7.85	$0.39	$8.24
19	Spaulding No. 3	Yes	No	$2.20	$7.92	$0.39	$8.30

TABLE 1-7
DAMS THAT COULD IMPACT DVCS DURING HYPOTHETICAL DAM BREACH SCENARIOS
CONSEQUENCE IMPACTS

Line No.	Dam	Frequency of event – TY 2027	Expected Safety consequence per year (EFs) – TY 2027	Expected Safety consequence per event (EFs) – TY 2027	Expected Financial consequence per year (2023 $M) – TY 2027	Expected Financial consequence per event (2023 $M) – TY 2027	Risk Score (risk-adjusted $M) – TY 2027
1	Bear, Lower No. 1	8.87E-05	1.42E-03	16.0	$0.3	$3,301.8	$1.8
2	Bear, Lower No. 2	7.64E-05	1.22E-03	16.0	$0.2	$2,785.4	$1.3
3	Bear, Upper	8.48E-05	1.36E-03	16.0	$0.3	$3,968.8	$2.1
4	Bucks Lake (Storage)	6.02E-05	2.22E-04	3.7	$0.3	$4,675.2	$1.9
5	Crane Valley	8.59E-05	1.64E-03	19.1	$0.2	$2,495.2	$1.3
6	Fordyce	1.32E-03	9.10E-03	6.9	$3.1	$2,362.8	$22.3
7	Lake Almanor	3.24E-03	2.06E-03	0.6	$2.5	$765.7	$17.4
8	Pit 1	3.47E-05	8.68E-04	25.0	$0.1	$2,585.4	$0.6
9	Pit 3	6.18E-04	2.04E-02	33.0	$5.4	$8,662.1	$39.2
10	Pit 4	8.41E-04	2.30E-04	0.3	$2.4	$2,842.3	$13.3
11	Pit 5 Open Conduit	1.70E-03	2.46E-02	14.5	$4.7	$2,788.0	$27.5
12	Pit 6	5.61E-04	1.57E-04	0.3	$1.7	$3,052.5	$9.7
13	Pit 7	8.40E-04	1.62E-04	0.2	$1.7	$2,023.8	$8.1
14	Relief	5.44E-05	9.51E-04	17.5	$0.4	$6,556.4	$2.4
15	Salt Springs	3.97E-04	7.53E-03	19.0	$2.1	$5,384.4	$14.4
16	Scott	9.47E-05	3.26E-03	34.5	$0.1	$862.9	$0.5
17	Spaulding No. 1	4.92E-03	6.68E-02	13.6	$2.1	$425.5	$20.6
18	Spaulding No. 2	6.22E-04	1.68E-02	27.1	$1.2	$1,905.5	$7.5
19	Spaulding No. 3	1.35E-04	9.08E-03	67.3	$0.4	$2,797.5	$3.2
20	All dams	4.03E-02	2.70E-01	6.7	$40.1	$994.2	$258.3

C. 2023-2026 Control and Mitigation Plan

Tables 1-8 and 1-9 list all the controls and mitigations PG&E included in its 2020 RAMP, 2023 GRC and 2024 RAMP (2024-2026 and 2027-2030). The tables provide a view as to those controls and mitigations that are ongoing, those that are no longer in place, and new mitigations. In the following sections, PG&E describes the controls and mitigations in place during the 2023-2026 period and then discusses new mitigations and/or significant changes to mitigations and/or controls during the 2027-2030 period.

TABLE 1-8
CONTROLS SUMMARY

Line No.	Control Number and Name	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2023-2026)	2024 RAMP (2027-2030)
1	C5 – Dam Safety Program[(a)]	X	Became LGUWR-C001		
2	LGUWR-C001 – DSP[(a)]		X	Changed to LGUWR-F001 as Foundational	Changed to LGUWR-F001 as Foundational
3	LGUWR-C001 – Maintenance			X	X

(a) In the 2024 RAMP moving forward, DSP (Dam Safety Program) is defined as a foundational activity.

TABLE 1-9
MITIGATIONS SUMMARY

Line No.	Mitigation Number and Name	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2023-2026)	2024 RAMP (2027-2030)
1	LGUWR-M001 – Internal Erosion Mitigations	X	X	X	X
2	LGUWR-M002 – Spillway Remediations	X	X	X	X
3	LGUWR-M003 – Seismic Retrofit	X	X	X	X
4	LGUWR-M004 – LLO Refurbishments	X	X	X	X
5	LGUWR-M005 – Physical Security			X	X

1. Controls

In the 2017 RAMP, PG&E defined five separate activities as controls: (1) Hydro O&M; (2) Facility Safety Inspections; (3) FERC and DSOD Inspections; (4) Part 12D Inspections and follow-up; and 5) DSP. The DSP was combined into a single DSP control beginning in 2020. However, the DSP is now considered a foundational activity consistent with the CPUC definition and is discussed later in this chapter.[23] PG&E defined LGUWR-C001 – Maintenance as a new control activity beginning in 2023. The section below provides more detail on this control.

LGUWR-C001 – Maintenance: The LGUWR-C001 - Maintenance comprises routine O&M activities. Examples include routine vegetation management, rodent abatement, and general maintenance activities for dams and around reservoirs. The costs of O&M maintenance activities are currently tracked at either a programmatic or areawide level, which made it difficult to identify dam-specific maintenance costs. Therefore, PG&E aggregated the costs of maintenance activities and allocated the cost equally across all dam tranches. PG&E notes that larger scope maintenance activities such as replacement of components or more significant concrete repairs can be capitalized and are instead treated as mitigations. A value of 5 percent was assigned for the effectiveness maintenance for the failure under normal operations conditions and the flood driver. Not performing LGUWR-C001 would increase PG&E's existing baseline risk to the higher "baseline risk."

2. Mitigations

a. Program Descriptions

Mitigations are comprised of risk reduction projects that are planned or are in process to reduce the likelihood of failure or consequences for dams. Mitigations can be capital or expense projects. There are five mitigation programs: (1) LGUWR-M001 – Internal Erosion Mitigations;

[23] D.21-11-009, p. 19 defines foundational programs and/or activities as "initiatives that support or enable two or more mitigation programs or two or more risks but do not directly reduce the consequences or the likelihood of risk events." For additional information on PG&E's treatment of foundational activities, see Exhibit (PG&E-2), Chapter 2, Section D.4.g.

(2) LGUWR-M002 – Spillway Remediations, (3) LGUWR-M003 – Seismic Retrofits, (4) LGUWR-M004 – LLO Refurbishments, and (5) LGUWR-M005 – Physical Security (new for the 2024 RAMP). Details for each mitigation program are discussed in the sections below.

LGUWR-M001 – Internal Erosion Mitigations: PG&E implements internal erosion mitigations (LGUWR-M001) to minimize the potential for internal erosion failure modes to initiate and develop for earth-fill and rockfill embankment dams. Mitigation projects for LGUWR-M001 include installing a downstream seepage berm with filter and drains and installing or maintaining a seepage barrier on the upstream side of the dam.

Implementing LGUWR-M001 mitigation projects will reduce the likelihood of the D3 (failure under normal operations) risk driver for the specific dam but does not change the safety and financial consequences in an event of dam failure.

LGUWR-M002 – Spillway Remediations: PG&E implements spillway remediation mitigations (LGUWR-M002) to ensure its dams can safely pass the design flood events. Mitigation projects for LGUWR-M002 include improvements to or rehabilitation of spillway control structures, spillway chutes, gates, log booms, and operators. Spillway remediations address the largest LGUWR driver, flood, and comprise the majority of spend as further detailed in Section D, 2027-2030 Proposed Control and Mitigation Plan.

Implementing LGUWR-M002 mitigation projects will reduce the likelihood of the D1 (flood) risk driver for the specific dam but does not change the safety and financial consequences in an event of dam failure.

In 2023, PG&E established a spillway Capital Improvement Program (CIP) to prioritize and plan long-term implementation of large capital projects for spillway remediation. The scope of these projects includes, but not limited to rehabilitating deteriorated spillways, retrofitting structural components to meet design criteria, and increasing the capacity of the spillways. There are currently 12 spillways in the 20-year CIP Program. The list of these spillways, along with the preliminary

"Begin Remediation" and "End Remediation" dates are provided in Table 1-10. For the 2024 RAMP, 8 of the spillways will be in various stages of design, permitting, and construction in years 2024 to 2030. PG&E notes that the spillways with remediation beginning in 2027 could be reprioritized if new, higher-risk projects are added to the CIP.

Long-term mitigations can sometimes take several years to plan, design, permit, and construct; therefore, IRRMs can be necessary to mitigate risk in the interim. Examples of IRRMs include emergency repairs or near-term capital projects, such as repair of concrete slab joints and surfaces, improvement of spillway training walls, or restoration of spillway crest elevations.

TABLE 1-10
LIST OF SPILLWAYS IN THE CIP

No.	Dam and Spillway	Begin Remediation	End Remediation
1	Bucks Diversion	Ongoing	2025
2	Tiger Creek Regulator	Ongoing	2027
3	McCloud dam	Ongoing	2030
4	Belden Forebay dam	2023	2033
5	Butt Valley dam	2023	2034
6	Lake Almanor dam	2023	2034
7	Bucks Storage dam	2027	2035
2	North Battle Creek dam	2030	2037
9	Macumber dam	2032	2039
10	Round Valley dam	2033	2040
11	Cape Horn dam	2035	2042
12	Philbrook dam	2037	2044

LGUWR-M003 – Seismic Retrofits: PG&E implements seismic retrofit mitigations (LGUWR-M003) to ensure dams and components will not fail under the seismic design loads. Mitigation projects for LGUWR-M003 include strengthening structural capability of the dams and components such as spillway gates, intake structures, and LLOs.

Implementing LGUWR-M003 mitigation projects will reduce the likelihood of the D2 (seismic) risk driver for the specific dam but does not change the safety and financial consequences in an event of dam failure.

LGUWR-M004 – LLO Refurbishments: PG&E implements LLO refurbishments (LGUWR-M004) to ensure the reservoir can be drained during an emergency or for dam maintenance. LLOs do not directly mitigate the three major drivers (flood, seismic, and normal) but maintaining reliable operation of the LLOs is critical to lower the reservoir after a seismic event or during the progression of internal erosion failure modes to prevent a more catastrophic failure. LLOs are also needed to lower the reservoir for performing maintenance and other risk reduction improvements. PG&E is also required by regulations to ensure the LLOs are maintained and in good operating condition. The scope of this LLO program includes the entire series of components that would be used to lower the reservoir. These components could include the LLO, power tunnels, and canals. For the purpose of RAMP, a deteriorated LLO will be added as a multiplier to the likelihood of either the seismic (D2) or normal operations (D3) risk driver.

LGUWR-M005 – Physical Security: Physical security (LGUWR-M005) is a new mitigation program for the 2024 RAMP. PG&E implements mitigations against physical attack (LGUWR-M005) to reduce the likelihood of malicious threats from third-party individuals or groups on dam safety. Mitigation projects for LGUWR-M005 include constructing physical barriers and installing surveillance monitoring systems.

Implementing LGUWR-M005 mitigation projects will reduce the likelihood of the D4 (physical attack) risk driver for the specific dam but does not change the safety and financial consequences in an event of dam failure.

The cost estimates for mitigation work planned for the 2024-2026 period are shown in Tables 1-11 and 1-12 below. Key mitigation projects identified by PG&E for this period are as follows:

b. Cost Estimates

LGUWR-M001 – Internal Erosion: Projects that continued from the 2020 RAMP are constructing new or repairing seepage liners for

Fordyce, Relief, and Courtright Dams. The seepage mitigation project for Main Strawberry Dam reported in the 2020 RAMP was completed.

New projects identified for the 2024 RAMP are projects to install rip rap or restore upstream slope to protect dam from reservoir wave action for Pit 1 Forebay and Wise Forebay Dams.

LGUWR-M002 – Spillway Remediation: Capital mitigation projects for the 2024 to 2026 period of 2024 RAMP primarily consists of spillway remediations (66.6 percent of total forecast), spillway gates remediations (20.5 percent), log boom replacements (6.9 percent), and others (1.1 percent). Programmatic forecast placeholders constituted approximately 4.9 percent (or $10 million) of the total forecast. The section below describes the mitigation projects in more detail:

- Spillway CIP:
  - Spillways in the CIP constitute the majority of capital spend in the 2024 to 2026 period.
  - Three of the spillways in the CIP that continued from the 2020 RAMP are mitigations for McCloud, Bucks Diversion, and Tiger Creek Regulator Dams.
  - New spillway projects identified for the 2024 RAMP are Belden Forebay, Butt Valley, and Lake Almanor spillways.
- Spillway Gates Refurbishment Projects:
  - Major spillway gates refurbishment projects, which are new for the 2024 RAMP, consist of replacing critical components (e.g., hoist chains, trunnion arms) and recoating the gates to provide weather protection.

The Scott Dam mitigation reported in the 2020 RAMP was completed. The areas of concrete deterioration were repaired per engineered repair methods.

LGUWR-M003 – Seismic Retrofit: Seismic retrofit for the Crane Valley intake tower was identified in the 2020 RAMP and the new completion date is 2026. PG&E also identified two new seismic retrofit projects, which were the Upper Peak Dam seismic retrofit and the Belden intake structure retrofit.

LGUWR-M004 – LLO Refurbishment: The total capital budget includes a programmatic budget placeholder of $4 million to address emergent LLO projects.

There are 13 capital projects for LGUWR-M004, including refurbishment of intake to power tunnel and LLO for Spaulding Dam No. 1 and upgrading intake/discharge (I/D) control for Courtright Dam.

LGUWR-M005 – Physical Security: The total capital budget includes a programmatic budget placeholder of $11.8 million to address emergent projects.

The capital mitigation projects for LGUWR-M005 comprise of installation of surveillance systems (51 percent of total capital budget), physical barriers (20 percent), and a programmatic budget placeholder (29 percent).

TABLE 1-11
MITIGATION COST ESTIMATES
2024-2026 EXPENSE
(THOUSANDS OF DOLLARS)

Line No.	Mitigation ID	Mitigation Name	2024	2025	2026	Total
1	LGUWR-M001	Internal Erosion	$530	$467	$100	$1,096
2	LGUWR-M002	Spillway	4,003	1,728	3,100	8,831
3	LGUWR-M003	Seismic retrofit	–	–	–	–
4	LGUWR-M004	LLO	500	1,000	3,000	4,500
5	LGUWR-M005	Physical Security	822	405	–	1,227
6		Total	$5,855	$3,599	$6,200	$15,654

Note: For additional details see Exhibit (PG&E-5), WP GEN-LGUWR-F.

Power Generation developed cost estimates shown in this table per the estimating method described in detail in the 2023 GRC, Exhibit (PG&E-5), Chapter 4, Section D Estimating Method, p. 4-63 to p. 4-65.

TABLE 1-12
MITIGATION COST ESTIMATES
2024-2026 CAPITAL
(THOUSANDS OF DOLLARS)

Line No.	Mitigation ID	Mitigation Name	2024	2025	2026	Total
1	LGUWR-M001	Internal Erosion	$54,441	$74,386	$91,599	$220,426
2	LGUWR-M002	Spillway	57,706	89,945	57,494	205,145
3	LGUWR-M003	Seismic retrofit	990	1,985	5,186	8,161
4	LGUWR-M004	LLO	18,274	31,393	24,790	74,457
5	LGUWR-M005	Physical Security	10,373	14,382	15,201	39,956
6		Total	$141,784	$212,090	$194,270	$548,144

Note: For additional details see Exhibit (PG&E-5), WP GEN-LGUWR-F.
Power Generation developed cost estimates shown in this table per the estimating method described in detail in A.21-06-021, the 2023 GRC, Exhibit (PG&E-5), Chapter 4, Section D Estimating Method, p. 4-63 to p. 4-65.

3. Foundational Activities

As discussed in Exhibit (PG&E-2), Chapter 2, foundational activities are programs that enable two or more control or mitigation programs but do not directly reduce the consequences or the likelihood of risk events. Table 1-13 describes the foundational activities that meet this definition and includes (1) information on the control or mitigation programs enabled and (2) the foundational activity program costs on a net-present value (NPV) basis that are included in CBR calculations for enabled control or mitigation programs.

PG&E's PG Organization's foundational activities are essential in managing the LGUWR risk and enabling its controls and mitigations, as well as compliance with FERC and DSOD regulations. Emergent deficiencies that could impact dam safety found by these foundational activities will be acted upon accordingly, either through additional foundational studies to better understand the deficiency, implementation of IRRMs, and/or permanent risk reduction projects. If needed, PG&E may implement additional inspection, surveillance, and monitoring activities until the emergent deficiencies are mitigated, either through revised operational procedures, and/or risk reduction projects. PG&E's DSP, along with Asset Management and O&M, manages and implements foundational activities. PG&E's foundational activities listed for the 2024 RAMP is LGUWR-F001 –

DSP and LGUWR - F002 - Security Program. The following sections provide detail on the foundational activities in place to manage PG&E's large portfolio of dams.

LGUWR-F001 – Dam Safety Program:

- Dam Inspections Program: Dam inspections and walkdowns are performed by O&M monthly and by dam safety engineers annually. Regulators (FERC and DSOD) perform dam safety inspections to confirm PG&E's dams are in good condition. Third-party, FERC-approved Independent Consultants also perform quinquennial comprehensive and periodic Part 12D dam safety inspections and design and performance reviews.
- Engineering Evaluations: Engineering evaluations to ensure dams meet the required performance during normal operations, seismic and flood loading. Engineering evaluations also include performing risk assessments for dams and its components.
- Instrumentation and Surveillance Monitoring Program: PG&E inspects and maintains instrumentation for dams. Data obtained by the instrumentation and surveillance monitoring is used to determine if PG&E's dams are performing within expected operating conditions.
- LLO and Spillway Gates Testing Program: PG&E performs annual exercises of all spillway gates and motor-operated LLO valves that were identified as critical dam safety equipment.
- Emergency Action Plans: A critical component of PG&E's DSP are its EAPs. These are required by FERC Dam Safety Regulations and contain critical information that supports PG&E's capability to reduce the consequence of a risk event. EAPs include preparatory and response measures, like instructions to operators about actions to be taken during an emergency and plans for notification of affected persons, appropriate governmental and law enforcement agencies, medical response units, and public safety organizations. PG&E's EAPs along with its EP&R team (described in Section B.b.3) are critical in the management of the LGUWR risk. The future of PG&E's EAPs and EP&R operations could include

improvements like enhanced meteorology and early warning detection, and automated notification systems and may be discussed in PG&E's 2027 GRC filing.

LGUWR-F002 – Physical Security Program: PG&E's security program assesses and identifies vulnerabilities in security for PG&E's high-hazard dams. The security program is responsible for developing security plans to describe responses to potential threats and plan for risk reduction measures.

TABLE 1-13
FOUNDATIONAL ACTIVITIES

Line No.	Foundational Activity ID	Foundational Activity Name	Foundational Activity Description	Enabled Control and Mitigation IDs	2027-2030 Millions of Dollars (NPV)[(a)]
1	LGUWR-F001	DSP	Inspections, analyses, investigations enabling controls and mitigations of LGUWR	LGUWR-C001, LGUWR-M001, LGUWR-M002, LGUWR-M003, LGUWR-M004, LGUWR-M005	$50.88
2	LGWUR-F002	Security Program	Plan for implementing physical security projects	LGUWR-M005[(b)]	$3.04
3		Total			$53.92

(a) NPV uses a base year of 2023.

(b) LGUWR-F002 enables a single mitigation program, LGUWR-M005 that comprises multiple dam safety projects. The foundational activity costs for LGUWR-F002 are allocated to individual projects within LGUWR-M005.

Note: For additional details see Exhibit (PG&E-5), WP GEN-LGUWR-F.

Power Generation developed cost estimates shown in this table per the estimating method described in detail in A.21-06-021, the 2023 GRC, Exhibit (PG&E-5), Chapter 4, Section D Estimating Method, p. 4-63 to p. 4-65.

There are additional activities and programs either planned or active throughout the PG Organization that are also foundational in managing risk, including the LGUWR risk. These activities and programs are the result of an AMS that has been put into place. For additional context of PG&E's foundational activities and programs, the remainder of this section provides an overview of PG's AMS. PG&E is assessing its current asset management capabilities and may highlight additional foundational activity and program needs in its 2027 GRC Application.

AMS Overview

The PG AMS is currently organized into eight asset families to ensure a holistic approach to managing its assets. These asset families include: (1) Dams, (2) Civil Infrastructure, (3) Powerhouses, (4) Asset Data, (5) Physical Data Assets, (6) Fossil, (7) Solar, and (8) Battery Energy Storage Systems.

This structure builds an AMS where safety, reliability, and cost can be optimized for the long term to meet business objectives, all while following a risk-based asset management approach. Each asset family has an Asset Management Plan that provides information on the risks, risk mitigations, strategies, objectives, and maintenance information needed to manage the lifecycle of the assets within the asset family. The asset family structure enables PG&E to implement asset management strategies consistently within and across the various asset families.

Since PG&E's 2020 RAMP filing, the PG Organization has established this AMS to align with International Organization for Standardization (ISO) 55001 requirements. PG achieved ISO 55001 certification in March 2022 and continues to assess its AMS through regular surveillance from an internationally recognized ISO 55001 auditor. PG plans to seek re-certification in 2025 and continues to grow and mature its program along the way. The controls and mitigation activities proposed in this chapter are in alignment with and supported by the commitment to maintaining this Asset Management ISO 55001 Certification going forward.

As PG matures the AMS and the asset family strategies that were first developed during the ISO 55001 certification process, it has become apparent that the LGUWR and other risks would benefit from additional investments into the AMS, including Asset Data, Physical Data, and Dams Asset Families. Doing so would expand PG's capacity to manage risk, through various foundational, control and mitigating activities. Some of these activities are either under development or in need of enhancement and may be included and expanded upon in more detail in PG&E's 2027 GRC filing. These include:

- Enhancement of the Asset Data Family, which includes all asset data required for the lifecycle management of assets within and across all asset families in the AMS, including the Dam Asset Family, which provides foundational support for the management and mitigation of LGUWR.
- Expansion of the Physical Data Asset Family, which includes assets related to communication systems, control systems and instrumentation that are used across multiple hydro asset families, including the Dam, Civil Infrastructure, and Powerhouse Asset Families. These assets provide enhanced visibility into the status and condition of PG's hydro assets, as well as control for systems that require fast response when imminent threats to safety or reliability present themselves. These would provide foundational support for AMS risk management, including the management of LGUWR.
- Growth of PG's Risk Management Program, including the expansion of its risk register, which will better inform risk-based decision making across the organization. For the hydroelectric fleet, this will focus on all watershed objectives (e.g., water delivery, recreation, environmental support, generation) and then identify the risks that could disrupt each of these objectives and which stakeholders would be impacted. As this analysis is completed, elements may be featured in future filings, including PG&E's 2027 GRC filing.
- New implementation or enhancement of programs under the AMS, including a Water System Maintenance Program, Powerhouse Maintenance Program, Vegetation Management Program, Rodent Management Program, Reservoir Debris Management Program, and Critical Support Facility Maintenance Program.
- Increased number and frequency of inspection activities and routine and interim maintenance and mitigations as informed by the AMS and its programs.
- Implementation of a Hydro Means and Work Methods Program to develop more comprehensive O&M standards and procedures to reduce operational risk, which also includes expanded training to improve and sustain a skilled and qualified workforce.

- Enhancement of PG&E's Hydro Public Safety Program aimed at public safety improvements across hydro waterways to reduce risk of public interaction with PG&E's assets.
- Enhanced meteorology and multi-use water modeling to optimize hydro forecasts and improve risk management.
- Increased staffing of key positions required for program implementation and enhancements.

D. 2027-2030 Proposed Control and Mitigation Plan

1. Changes to Controls

PG&E's LGUWR-C001 – Maintenance control remain unchanged for the 2027-2030 period. Table 1-14 below shows the expense cost estimates for the control work planned for the 2027-2030 period.

TABLE 1-14
CONTROLS COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030 EXPENSE

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[a]			
Line No.	Control ID	Control Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[b] [C]/([A]+[B])
1	LGUWR-C001	Maintenance	$6,440	$6,781	$6,927	$7,078	$18.8	$2.1	$26.2	1.3
2		Total	$6,440	$6,781	$6,927	$7,078	$18.8	$2.1	$26.2	1.3

(a) NPV uses a base year of 2023.
(b) CBR calculations include allocated Foundational Activity Program costs.

Note:
(1) For additional details see Exhibit (PG&E-5), WP GEN-LGUWR-F.
(2) Notes for controls 2027 to 2030:
- O&M LGUWR-C001 controls consist of area wide to programmatic wide planning orders for O&M routine maintenance activities such as vegetation management, rodent abatement, and general maintenance at the dams and reservoirs.
- LGUWR-C001 costs are estimated based on historical spend at a programmatic level.

2. Changes to Mitigations

The five mitigations (LGUWR-M001 through -M005) will also remain unchanged for the 2027-2030 period. Table 1-15 (expense) and Table 1-16 (capital) below show the cost estimates for the mitigation work planned from 2027-2030. The CBR and risk reduction scores for each mitigation are shown in the column from the right in both tables.

As explained further below for each mitigation, cost estimates for the five programs for the 2027-2030 time period are a combination of discrete project cost estimates and placeholder values for future emergent projects that have not yet been identified. These placeholder values represent approximately 36 percent of total capital spend. There are significant uncertainties in our 2027 through 2030 forecasts because PG&E's detailed outer-year forecast is still in development. The refined forecast will be submitted as part of the 2027 GRC filing and PG&E believes that the forecasts submitted in the GRC filing will at least meet these placeholder value amounts. For the purposes of computing risk reduction for the capital budget placeholders, PG&E assumes 3 dams a year require mitigation (3/60 exposure per dam) and risk effectiveness was assumed to be 50 percent.

Key mitigation projects identified by PG&E for the 2027-2030 period are described below:

LGUWR-M001 – Internal Erosion: Projects continued from the 2024 to 2026 period are constructing new or repairing seepage liners for Fordyce and Relief dams. Additional projects include installing rip rap to protect the embankment. The aggregated CBR score for LGUWR-M001 was less than one for the 2027 to 2030 period, which indicates that costs are higher than the modeled value of risk reduction. However, these projects are essential to minimize the potential for internal erosion failure modes that could lead to full or partial dam breach. Estimated placeholder budget forecast for emergent projects is $112 million, or approximately 74.2 percent of the total capital budget.

LGUWR-M002 – Spillway Remediation: Capital mitigation projects for the 2024 RAMP primarily consists of spillway remediation (73.1 percent of total forecast), spillway gates remediation (9.1 percent), and others

(1.1 percent). Programmatic forecast placeholders constitute approximately 16.6 percent (or $122 million) of the total forecast. The section below describes the mitigation projects in more detail.

- Spillway CIP:
  - Spillways in the CIP constitute the majority of the capital spend in the 2027 to 2030 period.
  - Ongoing projects from the 2024 to 2026 period are McCloud, Belden, Tiger Creek Regulator, Butt Valley, and Lake Almanor spillways.
- Spillway Gates Refurbishment Projects:
  - Major spillway gates refurbishment projects consist of replacing critical components (e.g., hoist chains, trunnion arms) and recoating the gates to provide weather protection.

The aggregated CBR score for LGUWR-M002 was less than one for the 2027 to 2030 period. Spillway and gates rehabilitation projects such as those for McCloud, Tiger Creek Regulator, Belden Forebay, and Lake Almanor dams can be large, complex, and require multiyear period for planning, design, permitting, and construction. However, spillways and gates are critical components that need to be operational during flood and normal conditions.

LGUWR-M003 – Seismic Retrofit: The scope of projects categorized as LGUWR-M002 included seismic retrofit of dams and their critical components to meet the seismic design criteria. Ongoing projects from the 2024 to 2026 period are the Belden intake structure and Upper Peak seismic retrofit projects. Although the aggregated CBR score for LGUWR-M003 was less than one for the 2027 to 2030 period, PG&E's dams are located near known faults and these mitigation projects are needed to ensure the dams will not catastrophically fail for earthquakes with magnitudes up to their design level.

PG&E is currently updating seismic stability analysis for dams with increased in deterministic ground motion following completion of the 2021 DSHR. Results of the stability analysis will be used to determine if risk reduction measures, which may include seismic retrofit of the dams, are needed. PG&E allocated $72 million (out of the total $84.4 million) dollars for placeholder budget, which will be used for future emergent seismic retrofit projects.

LGUWR-M004 – LLO Refurbishment: The total capital budget included a programmatic budget placeholder of $78 million to address emergent LLO projects. Three capital projects will continue from the 2024 to 2026 period.

LGUWR-M005 – Physical Security: The capital mitigation projects for the 2027 to 2030 period comprise installation of surveillance systems (47.5 percent of total capital budget), physical barriers (8.1 percent), and a programmatic budget placeholder (44.3 percent). Although the aggregated CBR score for LGUWR-M005 was less than one for the 2027 to 2030 period, physical security projects are essential in helping to detect, delay, deter and/or keep the public out of areas around PG&E’s dams that are not intended for public access. These areas may include security sensitive equipment that if tampered with may compromise safe and reliable operations.

TABLE 1-15
MITIGATIONS COST ESTIMATES, RISK REDUCTION, CBR, AND FACTORS AFFECTING SELECTION
2027-2030 EXPENSE

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[a]				
Line No.	Mitigation ID	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[b] [C]/([A]+[B])	Factors Affecting Selection
1	LGUWR-M002	Spillway	$7,050	$6,300	$6,300	$6,300	$694	$21	$651	0.9	All[c]
2		Total	$7,050	$6,300	$6,300	$6,300					

(a) NPV uses a base year of 2023.
(b) CBR calculations include allocated Foundational Activity Program costs.
(c) All factors: Compliance, Modeling Limitations, Risk Tolerance, and Operational Risk Execution Considerations.
Note: For additional details see Exhibit (PG&E-5), WP GEN-LGUWR-F.

Power Generation developed cost estimates shown in this table per the estimating method described in detail in A.21-06-021, the 2023 GRC, Exhibit (PG&E-5), Chapter 4, Section D Estimating Method, p. 4-63 to p. 4-65.

TABLE 1-16
MITIGATIONS COST ESTIMATES, RISK REDUCTION, CBR, AND FACTORS AFFECTING SELECTION
2027-2030 CAPITAL

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[a]				
Line No.	Mitigation ID	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[b] [C]/([A]+[B])	Factors Affecting Selection
1	LGUWR-M001	Internal Erosion	$24,748	$24,838	$50,874	$50,443	$137	$11	$58	0.4	All[c]
2	LGUWR-M002	Spillway	175,071	169,572	180,083	208,314	694	20	651	0.9	All[c]
3	LGUWR-M003	Seismic retrofit	12,160	12,190	30,000	30,000	76	7	38	0.5	All[c]
4	LGUWR-M004	LLO	23,647	22,801	25,997	30,000	94	8	123	1.2	
5	LGUWR-M005	Physical Security	14,661	10,680	$14,321	8,080	45	5	–	<0.1	All[c]
6		Total	$250,286	$240,081	$301,275	$326,837					

(a) NPV values are shown in $2023.

(b) CBR calculations include allocated Foundational Activity Program costs.

(c) All factors: Compliance, Modeling Limitations, Risk Tolerance, and Operational Risk Execution Considerations.

Note: For additional details see Exhibit (PG&E-5), WP GEN-LGUWR-F.

Power Generation developed cost estimates shown in this table per the estimating method described in detail in A.21-06-021, the 2023 GRC, Exhibit (PG&E-5), Chapter 4, Section D Estimating Method, p. 4-63 to p. 4-65.

3. Factors Affecting Mitigation Selection

Four of the aggregated mitigation categories for LGUWR have CBR scores lower than one for the 2027 to 2030 period. There are several reasons why PG&E chose to implement these mitigation projects even though the CBRs are low. These reasons are discussed below and are applicable for all five mitigation categories (LGUWR-M001 through LGUWR-M005), even if the mitigation category has a high aggregated CBR score.

Compliance requirements: PG&E dams are regulated by two governmental agencies: FERC and DSOD. PG&E is responsible for meeting compliance requirements and obligations to ensure its dams and associated components meet design requirements and can be operated in a reliable and safe manner. For example, dams are required to safely pass the design storm flows and do not fail catastrophically for earthquakes up to the design load. Critical components such as spillway gates and LLOs, along with their power supply and backups, need to be operational during dam safety emergencies and routine operations.

The investments needed to retrofit the dams and components to meet design requirements or for upkeeping do not always have CBR scores greater than one. In general, mitigation projects that are large, complex, and require multiyear design and construction tend to have lower CBRs because of the higher implementation costs. These examples include the seepage mitigation project for Lake Fordyce Dam, and spillway improvement projects for McCloud, Tiger Creek Regulator, and Butt Valley Dams.

Modeling limitations: While PG&E’s consequence model currently captures direct economic losses, it does not account for many other important consequences that are harder to quantify or require significantly more sophisticated modeling efforts.

The consequences for full dam breach that were currently not accounted for could include potential indirect economic loss, cost of environmental clean-up and rehabilitation, loss of environmental habitat (particularly for endangered species) and damage to historical cultural sites. Potential indirect economic loss includes long-term loss of agricultural land, and damages to factories, commercial industry, and transportation infrastructure that have regional impacts. The model also did not account for potential impacts to stability of the power grid that could result in unplanned power outage because generation from impacted powerhouses are suddenly unavailable.

The failure of critical components or partial dam breach could also have significant safety, environmental, financial, and contractual obligations (e.g., water delivery requirements) consequences. Sudden and unannounced uncontrolled release caused by failure of critical components could have safety consequences during peak recreational times; the change in temperature in the river and change of flow rate could adversely impact aquatic life.

Operational and Execution Considerations: PG&E's risk mitigations help minimize the likelihood of dam safety incidents. Dam safety incidents, including inoperable critical components or partial dam failure that lead to uncontrolled water releases, can result in significant impacts to PG&E's operations. To immediately address these dam safety incidents, PG&E may have to alter its operations and PG efforts until emergency repairs can be implemented. Depending on the type of incident and scope of damage, PG&E could impose operational restrictions to the reservoir elevation, drain the reservoir, or install cofferdams and pumps to provide access for temporary repairs. PG&E would also need to divert engineering, planning, and permitting resources from planned mitigation projects to implement emergency repairs. PG&E believes that it is almost always significantly more expensive to respond to a dam safety incident than to proactively maintain the dams and their components.

Risk Tolerance: The Commission has recognized the need for discussion and clear guidance on Risk Tolerance and has expressed its intention to address this topic in future Phases of the Risk OIR. In the meantime, PG&E's risk mitigation strategies are selected to ensure that safety remains PG&E's top priority even when the quantitative RAMP modelling indicates the costs are higher than the modeled value of risk reduction**.** All projects within the LGUWR mitigation programs (LGUWR-M001 through LGUWR-M005) are essential in ensuring the long-term safe and reliable operations of PG&E dams and are directed at preventing a large uncontrolled water release incident.

E. Alternative Mitigations Analysis

Each of PG&E's five mitigation programs, LGUWR-M001 through LGUWR-M005, are comprised of multiple projects that are diverse in scope and are often unique to the characteristics of the individual dams and the deficiencies to be addressed. Using the LGUWR-M001 program as an example, the type and scope of mitigation project to address an increase in seepage through the embankment would be different from addressing tree stumps and roots removal or extensive damage from rodent holes. At the project level, PG&E develops alternative analyses to inform determination of selected alternatives, considering key factors such as construction costs and schedule, difficulty in construction, lifecycle and maintenance costs, and serviceability. It is difficult to aggregate alternative analysis for individual projects with different scope and purpose into the higher level LGUWR-M001 mitigation program.

- An example of a project-level alternatives study that were considered for the Relief Dam seepage mitigation project is provided below. The alternatives considered included the proposed solution of installing a geomembrane liner and two alternatives: (1) local patching and (2) full shotcrete overlay. The following provides information on why the two alternatives were not chosen:
- <u>Local patching</u>: Local patching alternative was not selected because the localized patching efforts only target limited areas of significant deterioration and leaves the majority of the aging gunite liner in place. It involves significant continuous long-term repair and maintenance costs as other portions of aging liner deteriorate.
- <u>Full shotcrete liner</u>: Applying a reinforced shotcrete liner was not selected because of factors such as high cost, limited construction schedule, material vulnerable to cracking caused by dam deformations and freeze thaw, and the need to reapply sealant between shotcrete panels.

Tables 1-17 and 1-18 provide the cost information for the alternatives discussed. It is important to note that these alternatives are dam specific. Similar analysis may be applied for different projects but are not generally applied for all projects within the mitigation program.

TABLE 1-17
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR

				Thousands of Nominal Dollars				Millions of Dollars (NPV)[a]		
Line No.	Mitigation ID	Mitigation Name	Mitigation Project[b]	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	LGUWR-M001	Internal Erosion	Relief Dam – Resurface Upstream Liner				$87,900	$73.4	$14.8	0.20
2	LGUWR-A001[c]	Internal Erosion	Relief Dam – Local Patching				$82,709	$51.5	$0.2	<0.1

(a) NPV uses a base year of 2023.

(b) Costs for LGUWR-M001 – Relief Dam – Resurface Upstream Liner reflect updated costs since the preliminary costs were submitted for the RAMP forecasts. Final costs estimates may still change and will be provided in the 2027 GRC.

(c) The alternative mitigation analysis is a comparison of two risk mitigation options for a specific project within the LGUWR-M001 proposed mitigation plan. Line 1 in this table shows the cost estimates that are included in the LGUWR-M001 proposed mitigation plan shown in Table 1-16. Line 2 shows an alternative risk mitigation solution for the same project.

Note: For additional details see Exhibit (PG&E-5), WP GEN-LGUWR-F.

Power Generation developed cost estimates shown in this table per the estimating method described in detail in A.21-06-021, the 2023 GRC, Exhibit (PG&E-5), Chapter 4, Section D Estimating Method, p. 4-63 to p. 4-65.

TABLE 1-18
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR

				Thousands of Nominal Dollars				Millions of Dollars (NPV)[a]		
Line No.	Mitigation ID	Mitigation Name	Mitigation Project[b]	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	LGUWR-M001	Internal Erosion	Relief Dam – Resurface Upstream Liner				$87,900	$73.4	$14.8	0.20
2	LGUWR-A002[c]	Internal Erosion	Relief Dam – Full Shotcrete Overlay				$102,830	$85.9	$14.8	0.17

(a) NPV uses a base year of 2023.

(b) Costs for LGUWR-M001 – Relief Dam – Resurface Upstream Liner reflect updated costs since the preliminary costs were submitted for the RAMP forecasts. Final costs estimates may still change and will be provided in the 2027 GRC.

(c) The alternative mitigation analysis is a comparison of two risk mitigation options for a specific project within the LGUWR-M001 proposed mitigation plan. Line 1 in this table shows the cost estimates that are included in the LGUWR-M001 proposed mitigation plan shown in Table 1-16. Line 2 shows an alternative risk mitigation solution for the same project.

Note: For additional details see Exhibit (PG&E-5), WP GEN-LGUWR-F.
Power Generation developed cost estimates shown in this table per the estimating method described in A.21-06-021, detail in the 2023 GRC, Exhibit (PG&E-5), Chapter 4, Section D Estimating Method, p. 4-63 to p. 4-65.

Application: 24-05-
(U 39 G)
Exhibit No.: (PG&E-6)
Date: May 15, 2024
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT

EXHIBIT (PG&E-6)

(INTENTIONALLY LEFT BLANK)

Application: 24-05-
(U 39 G)
Exhibit No.: (PG&E-7)
Date: May 15, 2024
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT

EXHIBIT (PG&E-7)

ENTERPRISE HEALTH AND SAFETY, INFORMATION TECHNOLOGY, AND SHARED SERVICES

PACIFIC GAS AND ELECTRIC COMPANY
2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
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PACIFIC GAS AND ELECTRIC COMPANY
RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 1
RISK ASSESSMENT AND MITIGATION STRATEGY: CONTRACTOR SAFETY INCIDENT

A. Executive Summary

Contractor Safety Incident refers to any event resulting in a contractor serious injury or fatality as defined by PG&E's Serious Injury and Fatality (SIF) Standard[1] which is aligned with the Edison Electric Institute (EEI) Safety Classification Learning (SCL) model[2] excluding events resulting from asset failure. Contractors included in the analysis of Contractor Safety Incident risk are those that perform medium or high-risk work on behalf of Pacific Gas and Electric Company (PG&E or the Company). Events related to asset failure are covered in the asset management risks within Electric Operations (EO), Gas Operations (GO), and Energy Supply. The drivers for this risk event are separated into two categories (1) Contractor Pre-Qualification (including ISN data review, Variance, Emergent Work, Enhanced Contractor Safety Contract Terms) and (2) Contractor Safety Standard and Functional Area (FA)[3] Oversight procedures (Statement of Work, Hazard ID, Safety Plan Approval, Field Oversight, Observation Frequency) based on the Kern Order Instituting Investigation (Kern OII) Settlement Agreement (SA) with California Public Utilities Commission (CPUC).[4]

The cross-cutting factors of Records and Information Management, Physical Attack, Climate Change, and Emergency Preparedness and Response (EP&R) also impact this risk event.

Exposure to this risk is measured as hours worked for PG&E by the approximately 29,000 contractors that the Company employs each year. The

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1 SAFE-1100S SIF Standard.

2 EEI, SCL Model available at: <https://www.safetyfunction.com/scl-model> (accessed Apr. 30, 2024).

3 PG&E changed its title for lines of business (LOB) to FA in 2022.

4 Kern OII SA with CPUC approved in D.15-07-014.

mitigations PG&E will implement from 2023-2030 are designed to address the known risk drivers.

For the 2024 Risk Assessment and Mitigation Phase (RAMP) filing, PG&E identified four tranches for this risk based on high and medium-risk work activity categories. They include Electric work/Job Site; Vegetation Management (VM); Gas work/Job Site; and Transportation (On-Road Motor Vehicle Use). High-risk work can include activities such as: excavation and trenching beyond four feet; heavy equipment operation; utility tree trimming, clearance work and VM; general construction activities; welding and/or hot tapping of gas lines; and fault protection/grounding. Medium-risk work includes activities such as: geotechnical investigation; surveying and field inspection; material handling and compressed natural gas (NG)/liquified NG handling.

To evaluate risk event drivers the model includes sub drivers based on SIF (Potential and Actual) investigation cause data for the years 2020 through Q2 2023. For the Electric work/Job Site, VM, and Gas work/Job Site tranches, the driver responsible for most SIF incidents is Contractor Safety Standard and FA Oversight procedures. The driver responsible for most of the SIF incidents included in the Transportation (On-Road Motor Vehicle Use) tranche is Contractor Pre-Qualification.

Contractor Safety Incident has the sixth-highest 2027 Test Year (TY) Baseline Safety Risk Score ($38.60 million) and the twentieth-highest 2027 TY Baseline Total Risk Score ($38.60 million) of PG&E's 32 Corporate Risk Register risks.

PG&E is proposing a series of controls and mitigations to address the Contractor Safety Incident risk. The Contractor Safety Officer Criteria and the Contractor Safety Quality Assurance (QA) Review programs have the highest Cost-Benefit Ratio (CBR) scores. The Contractor Safety Officer Criteria and the SIF Capacity and Learning model have the highest total risk reduction scores.[5]

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[5] The information herein is subject to those limitations described in Ch. 2, Section D.

TABLE 1-1
RISK OVERVIEW

Line No.	Risk Name	Contractor Safety Incident
1	Definition	Any event resulting in a contractor[a] serious injury or fatality as defined by PG&E's SIF Standard[b] which is aligned with the EE International SCL Model.[c]
2	In Scope	PG&E contractors who perform high or medium risk work as defined by the Contractor Safety Standard. PG&E contractor SIF incidents that are not the result of an asset failure. Public serious injuries or fatalities as defined by the CPUC resulting from a Contractor Safety incident. A SIF Actual (Public) is defined as a fatality or personal injury requiring inpatient hospitalization for other than medical observations that an authority having jurisdiction has determined resulted directly from incorrect operation of equipment, failure or malfunction of utility-owned equipment, or failure to comply with any California Public Utilities Commission (CPUC or Commission) rule or standard. Equipment includes utility or contractor vehicles and aircraft used during the course of business. PG&E employee serious injuries or fatalities resulting from a Contractor Safety incident.
3	Out of Scope	PG&E contractor serious injuries or fatalities resulting from the failure of an asset or equipment malfunction.
4	Data Quantification Sources[d]	PG&E SIF (Potential and Actual) investigation reports (2020 to Q2 2023). ISNetworld (ISN) contractor hours (2020 through Q2 2023) ISN is a vendor that specializes in contractor safety prequalification and supplier management data. ISN's data is based on the contractor's working for PG&E. PG&E Public SIF Actual data from the CPUC Safety and Operational metrics reports.

(a) Contractors in scope for this risk are those contractors who perform high risk and medium risk work for PG&E. High risk and medium risk work are defined in Section B.4 below.
(b) SAFE-1100S SIF Standard.
(c) EEI, SCL Model available here: https://www.safetyfunction.com/scl-model.
(d) Source documents will be provided with the workpapers (WP).

1. Risk Overview

In 2023 PG&E employed approximately 994 active working contract partners, which included approximately 291,000 contract employees working more than 43.67 million hours supporting PG&E's diverse efforts across its FAs. PG&E's team of safety and health professionals is focused on preventing illness and injuries for both PG&E team co-workers and the contract partners who work with us. Beginning in 2016, PG&E implemented a formal Contractor Safety Program to help our contract partners reduce serious injuries and fatalities when working with PG&E. The program was implemented as required by the CPUC Kern OII SA.[6]

PG&E's Enterprise Health and Safety organization develops, enables, and integrates innovative, proactive safety and health solutions, including strategic planning and trending analysis; expert field safety support including field safety observations; continuous improvement of safety programs through the validation of essential controls; promoting safety culture; and investigation and human performance analysis. This organization establishes the framework for PG&E's enterprise safety and health programs, monitors their effectiveness, identifies areas for improvement, and oversees compliance with applicable regulatory requirements.

PG&E's Contractor Safety Program is supported by professionals with specific expertise in PG&E's Contractor Safety Program, as well as with the work performed by PG&E's contract partners. The Contractor Safety Program Director, Managers, and Analysts are responsible for the program governance, assessment and mitigation enhancements, while the Field Safety Managers and Safety Specialists conduct FA contract partner assessments, observe contract partner work for Cal/OSHA compliance, provide feedback, and coach and support FA co-worker and contract partner resources to improve safety performance.

PG&E's Contractor Safety Program establishes the minimum requirements for contract partner safety management and ensures that health and safety expectations associated with the work performed on behalf of PG&E are understood and communicated. The Program applies to all contract partners and their subcontractors (at any tier) performing medium- and high-risk work on behalf of PG&E on either PG&E-owned, or customer-owned sites and assets.[7] The Contractor Safety Program includes: contract partner and subcontractor pre-qualification prior to executing contracts and beginning work; safety planning integrated into the overall job plan; oversight procedures to monitor safe planning and work execution; and post-job evaluations to capture contractor safety

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6 Kern OII SA with CPUC approved in D.15-07-014.

7 High risk and medium risk work are described in Section B.4 below.

performance including lessons learned, identifying quality safety programs and pursuing continuous improvement.

PG&E has strengthened the contract partner company pre-qualification criteria by evaluating companies that have experienced a significant increase in resource headcount for PG&E-related work and for contractor partner companies that have been in business less than three years. This evaluation is through the Enterprise Contractor Management Organization Assessment (MOA) Procedure (SAFE-3001P-19).[8] The process includes an assessment of the contract partner company's organizational structure and their safety management systems. Companies that are not approved can no longer work for PG&E unless the FA that contracts their services elects to pursue the Contractor Safety Prequalification Variance Request Procedure (SAFE-3001P-11).

B. Risk Assessment

1. Background and Evolution

The Contractor Safety Incident risk was included in PG&E's 2020 RAMP[9] and was defined as "any event resulting in a contractor recordable injury or fatality, excluding events resulting from asset failure. Events related to asset failure are covered in the asset management risks within Electric Operations, Gas Operations, and Power Generation." In the 2024 RAMP the contractor safety risk name remains the same and the risk definition has been updated to align PG&E's serious SIF Standard.

The risk drivers in the 2024 RAMP have also continued to evolve. In the 2020 RAMP the risk drivers were based on OSHA injury classifications and supported by PG&E-specific contractor ISN data. For the 2024 RAMP, Contractor Safety Incident model drivers and sub drivers, no longer rely on external data. Instead, sub drivers are based on PG&E SIF (Potential and

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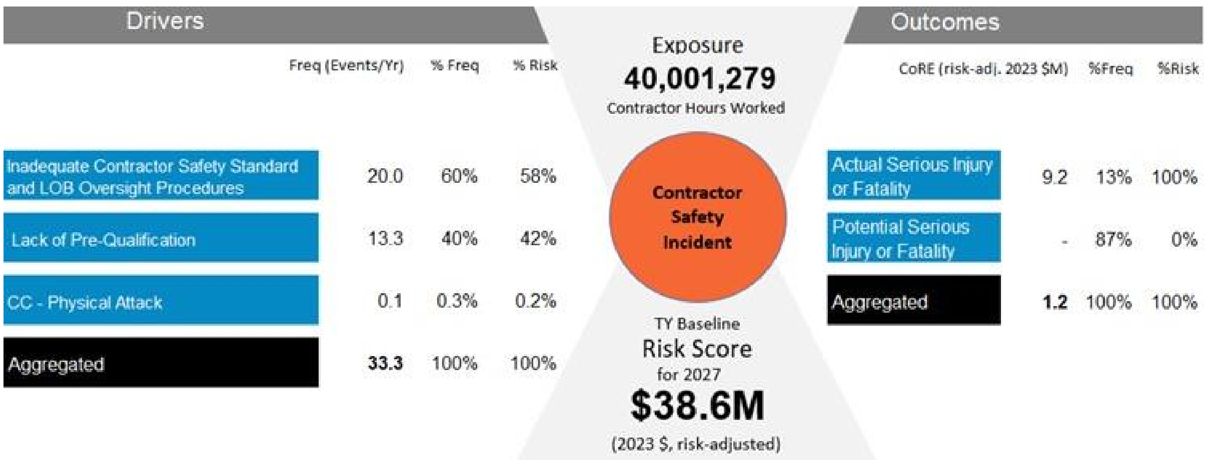
[8] SAFE-3001P-19 Enterprise Contractor MOA Procedure ensures that Environmental and Health and Safety (EHS) has evaluated contractors achieving a passing grade in ISN when a contractor has been identified as New in Business or having Rapid Growth and includes but is not limited to an assessment of the management staff for contractor or subcontractor(s) organizational structure, proposed spans of control, relevant work, EHS experience, employee training plan, implementation, and reference checks.

[9] PG&E's 2020 RAMP Report, A.20-06-012 (June 30, 2020).

Actual) investigations for the years 2020 through Q2 2023 aligned with the components of the Contractor Safety Program discussed as risk event drivers above.

2. Risk Bow Tie

FIGURE 1-1
RISK BOW TIE – 2027 TY



a. Difference from the 2020 Risk Bow Tie

The risk exposure in the 2024 RAMP bow tie was updated to the number of contract partner hours worked as used for determining risk exposure with the initial 2017 RAMP filing. Hours worked provides a better method of differentiating exposure between risk tranches. The 2020 RAMP bow tie had only one tranche whereas the 2024 RAMP bow has four tranches based on the number of hours worked by work type activity.

3. Exposure to Risk

Exposure to the risk is measured as number of contract partner labor hours performing high and medium risk work in each of the four risk tranches. The total exposure in the risk bow tie is based on an annual average of 40 million contract partner labor hours. PG&E contract partners conduct a wide variety of activities for PG&E across its FAs. From 2022-2023 the contract partner workforce population increased by 8 percent. For the first half of 2023, PG&E contract partner companies' self-reported a total of more than 18 million labor hours for PG&E specific work.

4. Tranches

PG&E identified four tranches for the Contractor Safety Incident risk based on a review of contractor safety SIF Potential and Actual incident investigation data including work activities. They are Electric work/Job Site; VM; Gas work/Job Site; and Transportation (On-Road Motor Vehicle Use). The tranches include high and medium risk work activities as described in the PG&E Contractor Safety Program Risk Matrix that is aligned to the PG&E Utility Standard, SAFE-3001S.

- High-risk work includes activities such as: excavation and trenching beyond four feet; heavy equipment operation; utility tree trimming, clearance work and VM; general construction activities; welding and/or hot tapping of gas lines; and fault protection/grounding; and
- Medium risk work includes activities such as: geotechnical investigation; surveying and field inspection; material handling and compressed NG/liquified NG handling.

PG&E tracks contract partner companies by prime companies (primes), those contract partner companies who work directly for PG&E, and sub-contractor companies (subs), those companies that have been retained by a prime contract partner company to provide services on behalf of PG&E. A break comparison of exposure (contract partner labor hours) and risk score (risk adjusted $) is below as Table 1-2.

TABLE 1-2
RISK SCORE AND EXPOSURE BY TRANCHE
(MILLIONS OF DOLLARS)

Line No.	Tranche	% Exposure	Safety Risk Score	Aggregated Risk Score	% Risk Score
1	Vegetation Management	30%	$18.22	$18.22	47%
2	Electric Work/Job Site	42%	$7.54	$7.54	20%
3	Transportation (On-Road Motor Vehicle Use)	8%	$8.55	$8.55	22%
4	Gas Work/Job Site	19%	$4.29	$4.29	11%
5	Total	100%	$38.60	$38.60	100%

5. Drivers and Associated Frequency

PG&E identified two main drivers for the Contractor Safety Incident risk tranches. In addition to the drivers, each tranche includes sub-drivers based on SIF (Potential and Actual) incident investigation cause data. The risk drivers and sub drivers are summarized discussed in Table 1-3 below:

TABLE 1-3
RISK DRIVERS AND SUB-DRIVERS

Line No.	Tranche	Driver	Sub-driver
1	Electric work /Job Site *(30 percent of the expected annual number of events)*	D1 – Contractor Safety Standard and FA Oversight procedures	Inadequate Site Safety Plan/Job Safety Analysis
			Inadequate Supervisory Oversight and Communication
			Inadequate Training and/or Job Knowledge
			Safe Work Procedures not followed or incomplete
		D2 – Contractor Pre-Qualification	Inadequate Training and/or Job Knowledge
			Safe Work Procedures not followed or incomplete
			Motor Vehicle Safe Operations requirements not followed or not understood
			Inadequate inspection and maintenance program/ Damaged, defective, or failed part
2	Vegetation Management *(41 percent of the expected annual number of events)*	D1 – Contractor Safety Standard and FA Oversight procedure	Inadequate Site Safety Plan/Job Safety Analysis
			Inadequate Supervisory Oversight and Communication
			Inadequate Training and/or Job Knowledge
			Safe Work Procedures not followed or incomplete
			Incomplete hazard tree inspection
			Power Tool protocols not followed
			Working at Height, incomplete fall prevention and protection
		D2 – Contractor Pre-Qualification	Inadequate Training and/or Job Knowledge
			Safe Work Procedures not followed or incomplete
			Motor vehicle roadway unanticipated hazards and evasive maneuvers to avoid roadway object

TABLE 1-3
RISK DRIVERS AND SUB-DRIVERS
(CONTINUED)

Line No.	Tranche	Driver	Sub-driver
3	Transportation (On-Road Motor Vehicle Use) *(32 percent of the expected annual number of events)*	D1 – Contractor Safety Standard and FA Oversight procedures	Inadequate Site Safety Plan/Job Safety Analysis
			Inadequate Supervisory Oversight and Communication
			Safe Work Procedures not followed or incomplete
			Hazardous road conditions
		D2 – Contractor Pre-Qualification	Inadequate Training and/or Job Knowledge
			Safe Work Procedures not followed or incomplete
			Motor Vehicle Safe Operations requirements not followed or not understood
			Inadequate inspection and maintenance program/Damaged, defective, or failed part
4	Gas work/Job Site *(4 percent of the expected annual number of events)*	D1 – Contractor Safety Std and FA Oversight procedures	Inadequate Site Safety Plan/Job Safety Analysis
			Inadequate Supervisory Oversight and Communication
		D2 – Contractor Pre-Qualification	Inadequate Training and/or Job Knowledge
			Inadequate inspection and maintenance program/Damaged, defective, or failed part

6. Cross-Cutting Factors

A cross-cutting factor is a driver, component of a driver, or a consequence multiplier that impacts multiple risks. PG&E is presenting seven cross-cutting factors in the 2024 RAMP. The cross-cutting factors that impact the Contractor Safety Incident risk are shown in Table 1-4 below.

TABLE 1-4
CROSS-CUTTING FACTOR SUMMARY

Line No.	Cross-Cutting Factor	Impacts Likelihood	Impacts Consequence
1	Climate Change	Yes*	No
2	Cyber Attack	No	No
3	EP&R	Yes*	No
4	Information Technology Asset Failure	No	No
5	Physical Attack	Yes	No
6	Records and Information Management (RIM)	No	Yes*
7	Seismic	No	No

Notes:
Yes The cross-cutting factor has been quantified in the model.
Yes* The cross-cutting factor does influence the baseline risk but has not been quantified in the model, or the cross-cutting factor may influence the baseline risk but further study is needed.
No The cross-cutting factor does not meaningfully influence the baseline risk.

A description of the cross-cutting factors and the mitigations and controls that PG&E is proposing to mitigate the cross-cutting factors is in Exhibit (PG&E-2), Chapter 3.

The climate change cross-cutting factor was assessed qualitatively with the use of a regional heat index analysis and research article review conducted by PG&E's Climate Resilience team. The analysis indicates an increased number of days where the heat index is above 103 degrees Fahrenheit through 2080. Research on the impacts of increased Heat Index values on cardiovascular deaths related to this show that hotter temperatures will lead to more heat related deaths. Research estimates that each summer, about 71 to 80 days will feel 90 degrees or hotter.[10] Based on these changes, researchers predict the number of annual heat-related cardiovascular deaths will increase 2.6 times for the general population—from 1,651 to 4,320 and that heat-influenced cardiovascular deaths could

[10] Khatana, Eberly, Nathan and Groeneveld, *Projected Change in the Burden of Excess Cardiovascular Deaths Associated With Extreme Heat by Midcentury (2036–2065) in the Contiguous United States*, (Oct. 2023), Circulation, available at: <https://www.ahajournals.org/doi/10.1161/CIRCULATIONAHA.123.066017> (accessed Apr. 30, 2024).

increase by 233 percent over 13-47 years.[11] Adults aged 65 and older are projected to have a 2.9 to 3.5 times greater increase in cardiovascular death due to extreme heat, compared with those aged between 20 and 64.[12] PG&E is continuing to monitor Heat illness Protection non-compliance as an EHS FA risk.

Changes in extreme weather conditions and their impacts to employee health and safety risks were not assessed. Additional research may be needed to determine if expected changes in extreme weather due to climate change will impact this risk event.

The EP&R cross cutting factor examines the drivers and consequences of inadequate planning or response to catastrophic emergencies. Inadequate emergency planning or response could have significant safety, reliability, and regulatory impacts. Emergency response and service restoration activities created by the events can increase demands on response and restoration utility workers and increase the risk of work-related fatigue and exposure to workplace hazards if not effectively managed. Long hours can contribute to fatigue and increase the risk for incidents. Research suggests that those who work more than 64 hours per week face 88 percent excess risk.[13]

7. Consequences

The basis for measuring the consequences of the Contractor Safety Incident risk are PG&E defined serious injuries aligned with the EEI SCL model definition or a fatality, and public serious injuries or fatalities as defined by the CPUC resulting from a Contractor Safety incident. There are no financial (i.e., workers compensation claims costs as they are covered by the contractor), electric or gas reliability consequences.

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11 *Ibid.*

12 *Ibid.*

13 Vegso, S., Cantley, L., Slade, M., et al., *Extended work hours and risk of acute occupational injury: A case crossover study of workers in manufacturing*. American Journal of Industrial Medicine (Aug. 2007), 50(8), 597-603. doi:10.1002/ ajim.20486.

The consequences of a Contractor Safety Incident risk event occurring are:

- A serious injury[14] or fatality (SIF Actual) occurs 13 percent of the time and accounts for 100 percent of the risk consequences.

PG&E relied on the PG&E SIF Potential (the remaining 87 percent of the incidents) and Actual Incident Investigation Reports from 2020 through Q2 2023 to analyze the safety consequences of a contractor safety incident. The review and analysis of the data was supported by PG&E Subject Matter Expert judgement to confirm the initial the incident information.

Table 1-5 below shows the risk event consequences. Model attributes are described in Exhibit (PG&E-2), Chapter 2.

TABLE 1-5
RISK EVENT CONSEQUENCES

Consequences										
					Natural Units Per Event	**Monetized Levels (2023 $M) of a Consequence Per Event**	**CoRE (risk-adjusted 2023 $M)**	**Natural Units per Year**	**Expected Loss per Year (2023 $M)**	**Attribute Risk Score (risk-adjusted 2023 $M)**
	CoRE	%Freq	%Risk	Freq	Safety EF/event	Safety $M	Safety	Safety EF/yr	Safety $M/yr	Safety
Actual Serious Injury or Fatality	9.2	13%	100%	4.2	0.60	9.19	9.20	2.53	38.58	38.60
Potential Serious Injury or Fatality	-	87%	0%	29.1	-	-	-	-	-	-
Aggregated	1.2	100%	100%	33.3	0.08	1.16	1.16	2.53	38.58	38.60

Note: For additional detail see Exhibit (PG&E-2), Chapter 2.

C. 2023-2026 Control and Mitigation Plan

Tables 1-6 and 1-7 below list all the controls and mitigations PG&E included in its 2020 RAMP, 2023 General Rate Case (GRC) and 2024 RAMP (2024-2026 and 2027-2030) for the Contractor Safety Incident risk. The tables provide a view as to those controls and mitigations that are on-going, those that are no longer in place, and new mitigations. In the following sections PG&E describes the controls in place during the 2023-2026 period, and then discusses new mitigations and/or significant changes to mitigations and/or controls during the 2027-2030 period.

14 EEI, SCL Model, available at: <https://www.safetyfunction.com/scl-model> (accessed Apr. 30, 2024).

TABLE 1-6
CONTROLS SUMMARY

Line No.	Control Number and Name	2020 RAMP 2020-2022	2023 GRC 2023-2026	2024 RAMP 2024-2026	2024 RAMP 2027-2030
1	CNTSI-C001 – Enhanced Standard Contract Terms and Conditions	X	Included in CNTSI-PRGA	Included in CNTSI-PRGA	Included in CNTSI-PRGA
2	CNTSI-C002 – Contractor Safety Pre-Qualifications	X	Included in CNTSI-PRGA	Included in CNTSI-PRGA	Included in CNTSI-PRGA
3	CNTSI-C003 – Contractor Safety Standard and FA (previously LOB) Contractor Oversight Procedures	X	Included in CNTSI-PRGB	Included in CNTSI PRGB	Included in CNTSI PRGB
4	CNTSI-C004 – Contractor Safety Plans	X	Included in CNTSI-PRGB	Included in CNTSI-PRGB	Included in CNTSI-PRGB
5	CNTSI-C005 – Contractor Hazard Analysis	X	Included in CNTSI-PRGB	Included in CNTSI-PRGB	Included in CNTSI-PRGB
6	CNTSI-C006 – FA (previously LOB) Contractor Safety Oversight	X	Included in CNTSI-PRGB	Included in CNTSI-PRGB	Included in CNTSI-PRGB
7	CNTSI-C007 – FA (previously LOB) Compliance Assessments	X	Included in CNTSI-PRGB	Included in CNTSI-PRGB	Included in CNTSI-PRGB
8	CNTSI-C008 – Corrective Action Program (CAP) for Contractor Issues	X	Included in CNTSI-PRGB	Included in CNTSI-PRGB	Included in CNTSI-PRGB
9	CNTSI-C009 – Contractor Post-Job Safety Performance Review	X	Included in CNTSI-PRGB	Included in CNTSI-PRGB	Included in CNTSI-PRGB
10	CNTSI-C010 – SIF Incident Governance and Oversight	Mitigation CNTSI-M01B	Included in CNTSI-PRGB	Included in CNTSI-PRGB	Included in CNTSI-PRGB
11	CNTSI-C011 – Contractor Safety Officer Criteria	Enhanced as CNTSI-M018	Enhanced as CNTSI-M18	See mitigation below	Becomes a control
12	CNTSI-C012 – Cause Evaluation Standard and procedures (formerly CAP Issues criteria)	X	Included in CNTSI-PRGB	Included in CNTSI-PRGB	Included in CNTSI-PRGB
13	CNTSI-C013 – ISN Rapid Growth Tracking and Contractor Evaluations	X	Included in CNTSI-PRGB	Included in CNTSI-PRGB	Included in CNTSI-PRGB

TABLE 1-6
CONTROLS SUMMARY
(CONTINUED)

Line No.	Control Number and Name	2020 RAMP 2020-2022	2023 GRC 2023-2026	2024 RAMP 2024-2026	2024 RAMP 2027-2030
14	CNTSI-C014 – In-field training visibility through ISN Individual Badge Feature (Formerly OSHA Program Training Requirements) (foundational)	Enhanced with CNTSI-M017	Enhanced with CNTSI-M017	CNTSI-PRGB (foundational)	CNTSI-PRGB (foundational)
15	CNTSI-C015 – Standardized Safety Plan and Job Safety Analysis (JSA) Templates	X	Included in CNTSI-PRGB	Included in CNTSI-PRGB	Included in CNTSI-PRGB
16	CNTSI-C016 – PG&E Specific Hazards Communication Process	Removed as Duplicative	X	X	X
17	CNTSI- C017 – Tools and Technology	Unbundled and removed	X	X	X
18	CNTSI-C018 FA (previously LOB) to Conduct Contractor Forums	X	Included in CNTSI-PRGB	Included in CNTSI-PRGB	Included in CNTSI-PRGB
19	CNTSI-C019 Contractor Safety Program Orientation	X	Included in CNTSI-PRGB	Included in CNTSI-PRGB	Included in CNTSI-PRGB
20	CNTSI-C020 Enhance Contractor Post-Job Performance Evaluation	X	Included in CNTSI-PRGB	Included in CNTSI-PRGB	Included in CNTSI-PRGB
21	CNTSI-C021 Automated System for Improving Processes through ISN	X	CNTSI-PRGB (foundational)	CNTSI-PRGB (foundational)	CNTSI-PRGB (foundational)
22	CNTSI-C022 Contractor Field Safety Observations	Discussed as a mitigation	X	X	X

Notes: CNTSI-PRGA: Contractor Pre-Qualification Program.
CNTSI-PRGB: Contractor Safety Oversight and Compliance Program.

TABLE 1-7
MITIGATIONS SUMMARY

Line No.	Mitigation Number and Name	2020 RAMP 2020-2022 Mitigations	2023 GRC 2023-2026 Mitigations	2024 RAMP 2024-2026 Mitigations	2024 RAMP 2027-2030 Mitigations
1	CNTSI-M011a – Safety Scorecard (now Safety Evaluation Process improvements)	X	Included with Control CNTSI-C003		
2	CNTSI-M011b – Work Permits	X	Determined to be infeasible		
3	CNTSI-M012a – ISN's Individual Badge Feature	X	Becomes Control CNTSI-C014		
4	CNTSI-M012b – Establish Tool for Capturing Contractor Near-Hits and Good-Catches	X	X		Becomes a Control (CNTSI-C023); operationalized through 2030
5	CNTSI-M013 – Contractor On-Boarding Requirements	X	Included with Programmatic Safety Plan/Project Specific Safety Plan review and approval process (CNTSI-C004)		
6	CNTSI-M014 – Contractor Safety Field Inspections	X	Becomes a Control CNTSI-C022		
7	CNTSI-M015 – Contractor Safety Handbook (foundational)	X	X	Becomes a foundational control enhancement for CNTSI-C001	Becomes a foundational control enhancement for CNTSI-C001
8	CNTSI-M016 – Tracking Contractor Workers	X	Determined to be infeasible		
9	CNTSI-M017 (enhancement to CNTSI-C014) –OSHA Programs Training Requirements	X	Becomes an enhancement to foundational control CNTSI-C014		
10	CNTSI-M018 (enhancement to CNTSI-C011) – Contractor Safety Officer Criteria	X	X		Becomes a control enhancement to CNTSI-C011; operationalized through 2030 as control CNTSI-C024

1. Controls

The list of controls below reflects the 2023 baseline for the risk and are anticipated to remain in place through 2030.

- **CNTSI-C001 – Enhanced Standard Contract Terms and Conditions:** The enhanced Standard Contract Terms and Conditions, which are inserted into each of the prime contractors' contracts, are specific safety-related expectations and conditions based on the Contractor Safety Program Standard SAFE-3001S. Ongoing evaluations are conducted through the FA compliance assessment process to assess effectiveness and identify any gaps.

  PG&E Contract terms require that, following a serious public or worker safety incident, the contractor will conduct a cause evaluation, share the analysis with PG&E, and cooperate and assist with PG&E's cause evaluation analysis and corrective actions for the incident, and regulatory investigations and inquiries, including but not limited to Safety Enforcement Division's investigations and inquiries. Under the enhanced Safety Contract Terms, PG&E has the right to:

  1) Designate safety precautions in addition to those in use or proposed by the contractor;
  2) Stop work to ensure compliance with safe work practices and applicable federal, state and local laws, rules and regulations;
  3) Require the contractor to provide additional safeguards beyond what the contractor plans to utilize;
  4) Terminate the contractor for cause in the event of a serious incident or failure to comply with PG&E's safety precautions;
  5) Review and approve criteria for work plans, which include safety plans; and
  6) Require the contractor to promptly, thoroughly, and transparently investigate all safety incidents that occur during Contractor's PG&E related work in compliance with PG&E's Enterprise Cause Standard,[15] including all SIF-Actual and SIF-Potential incidents,

[15] SAFE-1100S – Serious Injury and Fatality (SIF) Standard.

which shall be investigated jointly with PG&E, taking into account the priority and needs of OSHA and other regulator investigations.

This control is part of the Contractor Pre-Qualification Program (CNTSI-PRGA).

- **CNTSI-C002 – Contractor Safety Pre-Qualification:** The Contractor Safety program's pre-qualification process establishes criteria for contractors to qualify to perform work for PG&E. The criteria include total recordable injury and days away/restricted duty/transferred (DART) rates, number of fatalities, and confirmed OSHA citations.

  PG&E leverages the capabilities of ISN to collect performance and safety compliance program information from all prime and subcontractors that conduct work classified as high or medium risk. PG&E is responsible for the performance of its contractors. As part of this effort, ISN, a third-party administrator, independently assesses contractors' historical safety data, and safety, drug/alcohol, and written safety programs to evaluate whether contractors meet PG&E's minimum performance standards and have the necessary risk management programs in place to proactively mitigate risk. A variance to work for PG&E is required for contractors who do not meet the prequalification requirements. The variance process includes a review of the contractor's safety performance, an improvement plan and the business need in relation to the proposed scope of work (SOW). The decision to award a variance requires VP and Chief Safety Officer approval, or CEO designee approval.

  PG&E has implemented a Driving Safety Program. This program is intended to ensure our prime contractors and subcontractors are meeting the PG&E driving program expectations, as well as the Department of Transportation's regulatory agencies, and best-in-class procedures adapted from the American National Standards Institute (ANSI) Z15.1 2017 standard. PG&E continues to strengthen the requirements in the areas of fatalities and safety performance evaluation, including requiring a mitigation plan, and adding the requirement of a safety observation program.

Ongoing evaluations are conducted through the FA compliance assessment process to assess effectiveness and identify any gaps. This control is part of the Contractor Pre-Qualification Program (CNTSI-PRGA).

- **CNTSI-C003 – Contractor Safety Standard and FA Contractor Oversight Procedures:** The Contractor Safety Standard and the associated FA contractor safety oversight procedures set requirements for managing medium and/or high-risk contract work, including procedural steps for each FA in providing work oversight and management for their contractors. These procedures include providing a post-job safety performance evaluation of contractor work and sharing lessons learned resulting from safety incidents. Ongoing evaluations are conducted through the FA compliance assessment process to assess effectiveness and identify any gaps in procedure implementation. The Enterprise Health and Safety Contractor Safety team has established a formal review and approval process in 2019 for any new or revised procedures and included an approval requirement in the Contractor Safety Standard SAFE-3001S.

  In 2020 – 2022, PG&E implemented a safety scorecard for contractor performance evaluations as mitigation CNTSI-M011a to determine whether contractors need improvement in their performance or if they need a probationary period with a possible safety improvement plan or a deep dive safety assessment. This mitigation was incorporated into existing contractor safety procedures, SAFE-3001S-B005, Contract Safety Performance Evaluation and SAFE-3001P-24, Enterprise Contractor Safety Stand Down and Probation Procedure.

  This control is part of the Contractor Safety Oversight and Compliance Program (CNTSI-PRGB).

- **CNTSI-C004 – Contractor Safety Plans:** Safety plans are developed by the contractor and are reviewed and approved by PG&E prior to commencing high risk work and some medium risk work. These plans are required to address the SOW to be performed and identify specific site or task hazards, and mitigations of those hazards prior to beginning work. Additionally, these plans include a requirement to perform a hazard analysis (Refer to CNTSI-C005 for Job Hazard Analysis/tailboard requirements) prior to beginning medium and/or high-risk work activities. Ongoing evaluations are conducted through the FA compliance assessment process to assess effectiveness and identify any gaps. The process also establishes minimum safety training requirements and qualifications for safety plan approvers.

In 2020 – 2022, PG&E implemented mitigation CNTSI-M013, Contractor Onboarding, the onboarding was incorporated into the Programmatic Safety Plan/ Project Specific Safety Plan review and approval process as part of this control.

This control is part of the Contractor Safety Oversight and Compliance Program (CNTSI-PRGB).

- **CNTSI-C005 – Contractor Hazard Analysis:** Contractors perform a job hazard analysis as part of their daily tailboard process as a method of identifying, mitigating and communicating known or potential hazards to their employees and subcontractors (at all tiers) prior to commencing work. These analyses are required prior to the execution of work and re-enforce the requirements established in the approved safety plans (refer to C4 for Contractor Safety Plans). Ongoing evaluations are conducted through the FA compliance assessment process to assess effectiveness and identify any gaps. This control is part of the Contractor Safety Oversight and Compliance Program (CNTSI-PRGB).
- **CNTSI-C006 – FA Contractor Safety Oversight including Field Safety Observations and High Energy Controls Assessments (HECA):** The FAs and Corporate Field Safety provide oversight of contactors by conducting field safety observations of crews, using SafetyNet® observation software, to validate compliance with PG&E and regulatory safety requirements, while identifying safe/unsafe behavior and/or conditions. This allows PG&E to aggregate large quantities of data from observed at-risk behaviors and/or conditions from multiple job sites and projects. Analysis of this data allows each FA to better understand the specific areas of risk exposure and to target mitigation resources to those specific risks.

In 2023, PG&E initiated the pilot phase of HECA and has integrated the assessments into the Safety Observations program as of January 1, 2024. HECA is a new method of measuring and monitoring safety by assessing whether front-line employees are adequately protected against life-threatening hazards. HECA is computed as the percentage of high-energy hazards that have corresponding direct controls.

This control is coordinated with the employee SIF Prevention Program and Field Oversight Program (EMPSI-PRGC).

- **CNTSI-C007 – FA Compliance Assessments:** These assessments focus on compliance with the requirements outlined in each organization's procedures, including identifying any nonconformance and correcting them through PG&E's CAP. The assessments also focus on PG&E work that utilizes contractors performing medium and/or high-risk activities and are conducted across all organizations by members of the Corporate Contractor Safety team. The assessment results, including any related findings, are reported out post-assessment at the FA level and quarterly at an enterprise level. This control is part of the Contractor Safety Oversight and Compliance Program (CNTSI-PRGB).
- **CNTSI-C008 – CAP for Contractor Issues:** CAP continues to be used for contractor FA assessment non-conformances issues. CAP provides a process to document non-conformances identified from the FA compliance assessments (refer to control CNTSI-C007 for FA Compliance Assessments) and track issues to closure. This control is part of the Contractor Safety Oversight and Compliance Program (CNTSI-PRGB).
- **CNTSI-C009 – Contractor Post Job Safety Performance Review:** FAs complete safety performance evaluations for contractors at the end of project work or at minimum annually for multi-year projects. Post-job performance evaluations are entered into each contractor's ISN account and factor into each contractor's pre-qualification status and is used to determine future contract award. Ongoing evaluations are conducted through the FA compliance assessment process to assess effectiveness

and identify any gaps. This control is part of the Contractor Safety Oversight and Compliance Program (CNTSI-PRGB).

- **CNTSI-C010 – SIF Incident Governance and Oversight:** PG&E has two established procedures for SIF incident governance: (1) The SIF Manual, SAFE-1100M, that outlines the process for after a SIF occurs (PG&E employee or contractor) from the necessary notifications through the full investigation process; and (2) The procedure for non-SIF incidents involving contractors, SAFE-1100P-2, that provides a structure for evaluating the quality of the required contractor investigation and associated corrective actions, determining the extent of condition throughout PG&E, and developing and implementing corrective actions based on the extent of condition. Both procedures have processes required for entering issues into CAP for evaluation and corrective actions that were previously identified in CNTSI-C012 (CAP Issue Criteria), which has now been removed and incorporated into this control. This control is part of the Contractor Safety Oversight and Compliance Program (CNTSI-PRGB).
- **CNTSI-C012 – Cause Evaluation Standard and Procedures (formerly CAP issues criteria):** New control beginning in 2024, each FA has detailed procedures to implement the Cause Evaluation Standard that are customized to address the unique characteristics and needs of the organization. The Cause Evaluation Standard is reviewed on an annual basis and is subject to modification, within the terms of the Kern OII SA, at PG&E's discretion. This control is part of the Contractor Safety Oversight and Compliance Program (CNTSI-PRGB).
- **CNTSI-C013 – ISN Rapid Growth Tracking and Contractor Evaluations:** Utilizes ISN to track the rapid growth of contractors that have increased their headcount significantly for PG&E work. PG&E's Corporate Contractor Safety team performs Management and Organizations reviews of the contractor's safety management systems in place to support the workforce expansion. This control is an enhancement of CNTSI-C002 (Contractor Safety Prequalification) and is part of the Contractor Pre-Qualification Program (CNTSI PRGA).

- **CNTSI-C015 – Standardized Safety Plan and JSA Templates:** Standard templates for safety plans and JSAs allow PG&E to establish baseline requirements across all organizations. The requirements are included in contract terms and conditions. This program is an enhancement of control for CNTSI-C004 (Contractor Safety Plans) and CNTSI-C005 (Contractor Hazard Analysis/Daily Tailboards). Ongoing evaluations are conducted through the FA compliance assessment process to assess effectiveness and identify any gaps. This control is part of the Contractor Safety Oversight and Compliance Program (CNTSI-PRGB).
- **CNTSI-C018 – FAs to Conduct Contractor Forums:** Each organization that performs contractor high and medium risk work conducts safety forums with contractors to partner on safety topics, lessons learned and performance feedback. Ongoing evaluations are conducted through the compliance assessment process to assess effectiveness and identify any gaps. This control is part of the Contractor Safety Oversight and Compliance Program (CNTSI-PRGB).
- **CNTSI-C019 – Contractor Safety Program Orientation:** The Contractor Safety Program Orientation SAFE-0102 is web-based training, created for PG&E employees who oversee contractors and initiated in 2018 by the PG&E Learning Academy as an optional course and does not require mandatory enrollment. This control is part of the Contractor Safety Oversight and Compliance Program (CNTSI-PRGB).
- **CNTSI-C020 – Enhance Contractor Post-Job Performance Evaluation:** Contractor post-job performance evaluation scorecard criteria have been in place as a control since 2018. This control is part of the Contractor Safety Oversight and Compliance Program (CNTSI-PRGB).
- **CNTSI-C021 – Automated System for Improving Processes through ISN:** An automated system for tracking, trending, and generating reports to improve processes through ISN. This system is foundational in that it supports several contractor safety program controls through 2030 but does not in and of itself directly reduce the consequences or

reduce the likelihood of risk event. This control is part of the Contractor Safety Oversight and Compliance Program (CNTSI-PRGB).

- **CNTSI-C022 (formerly CNTSI-M014) – Contractor Field Safety Observations:** New control beginning in 2024, PG&E performs field safety observations including unannounced work site visits. The Contractor Safety Standard SAFE-3001S requires the FAs to perform safety observations of their contractors. The Enterprise Health and Safety organization performs field safety observations on both contractors who perform high and medium risk work activities and employees. This control is part of the Contractor Safety Oversight and Compliance Program (CNTSI-PRGB).

2. Mitigations

The list of the mitigations represents the mitigations implemented in the 2023-2026 period that will affect the 2027 Test Year Baseline Risk Value. Mitigation cost estimates are summarized in Tables 1-8 below.

- **CNTSI-M012b – Contractor Near hits/Good Catches:** Establish a method for capturing both PG&E employee and contractor near hits/good catches and share lessons learned. This mitigation was implemented in 2023 with the development of monthly Contractor newsletters, which includes safety spotlight, lessons learned, near-hits/good catches, and additional program information. Enterprise Contractor Safety also partnered with Enterprise Health & Safety Communications to send out an additional bi-weekly newsletter to Contractors in 2023. This mitigation will be operationalized though 2030 and transitions to control CNTSI-C023, part of the Contractor Safety Oversight and Compliance Program (CNTSI-PRGB).
- **CNTSI-M018 – Contractor Safety Officer Criteria (enhancement to CNTSI-C011):** Develop and implement criteria for when contractors are required to provide a Safety Officer, or a designated safety representative. This mitigation is an enhancement of CNTSI-C006 (FA Contractor Safety Oversight). By implementing this requirement, the contractor will provide additional safety oversight during the execution of work. This mitigation was implemented in 2023 with the publication of

SAFE-3001S-B004 and will be operationalized through 2030, transitioning to control CNTSI-C024.

- **CNTSI-M019 – Contractor Safety QA Reviews:** CSQARS are conducted with selected Contractors with adverse trends in safety performance and who are at risk of experiencing a Serious Injury or Fatality. The purpose is to partner directly with our contract partners, perform a comprehensive review of their safety programs and culture, and implement controls to eliminate serious injuries and fatalities. The contractors are invited to participate in a six-week examination of their safety culture within their company where opportunities are identified and undergo a barrier analysis; corrective actions are then designed and implemented. Following the successful completion of the initial six weeks, PG&E checks in with contractors every 30 days for a minimum of three months to conduct an effectiveness review to ensure the corrective actions were implemented as designed, were effective and self-sustaining, and do not expose employees to unforeseen hazards. As of the end of 2023, 19 PG&E Contractors completed a CSQAR and not one of them has experienced a serious injury or fatality, and only three have experienced SIF Potential incidents. Each post CSQAR SIF Potential event is properly evaluated, and controls are implemented and validated in the field. The CSQARS mitigation transitions to control CNTSI-C026 at the end of 2030.
- **CNTSI-M020 – SIF Capacity & Learning Model (both employees and contract partners):** New for 2024, the SIF Capacity and Learning model redefines safety as measured by the presence of essential controls and the capacity to experience failures safely. Worksite essential controls directly target the “stuff that can kill” or seriously injure a co-worker or contract partner. When the controls are installed, verified, and used properly, they are not vulnerable to human error. Looking at safety differently with the SIF Capacity and Learning Model advances how PG&E understands, manages, and prevents serious injuries and fatalities (SIFs). Instead of measuring success by the number of incidents, safety is defined by the presence of controls that give coworkers the ability to “fail safely.”

Implementation of the SIF Capacity and Learning model includes the use of ten Human Performance (HU) Tools which include: Questioning Attitude, Tailboards and Pre-Job Brief, Situational Awareness, Self-Checking (STAR), Two-Minute Rule, Three-Way Communication, Stop When Unsure, Procedure Use and Adherence, Phonetic Alphabet, and Placekeeping (i.e., physically marking steps in a procedure or other guiding document that have been completed). The HU Tools are deeply connected to the SIF Prevention Program and in addition to Stop Work Authority allow coworkers to slow things down and reduce the chances of human errors caused by internal and external factors. When used effectively, these tools can also help ensure essential controls remain in place and do not break down. The SIF Capacity & Learning Model transitions to control CNTSI-C025 in 2029.

TABLE 1-8
MITIGATION COST ESTIMATES
2024-2026 EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Mitigation ID [(a)]	Mitigation Name	2024	2025	2026	Total
1	CNTSI-M012b	Contractor Near Hits and Good Catches	$100	$100	$100	$300
2	CNTSI-M018	Contractor Safety Officer Criteria	$100	$100	$100	$300
3	CNTSI-M019	Contractor Safety QA Reviews	$300	$300	$300	$900
4	CNTSI-M020, EMPSI-M020	SIF Capacity and Learning model	$85	$80	$80	$245
5		Total	$585	$580	$580	$1745

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

Note: For additional details see Exhibit (PG&E-7), WP EHS-CNTSI-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

3. Foundational Activities

As discussed in Exhibit (PG&E-2), Chapter 2, foundational activities are programs that enable two or more control or mitigation programs but do not directly reduce the consequences or the likelihood of risk events. The Commission requires IOUs to include forecast costs of foundational activities in the CBR calculations for the control and mitigation programs that the foundational activities enable, subject to minimum cost thresholds.[16] This section lists foundational activities that support two or more planned mitigations or controls over the 2027-2030 period. However, costs for the foundational activities are below the minimum threshold for inclusion in CBR calculations.

- **CNTSI-C014 – In-field training visibility through ISN Individual Badge Feature (formerly CNTSI-M012a):** s foundational as a field validation process for contractor training compliance with PG&E required training using the ISN badging process. The field validation process for contractor training compliance with PG&E required training using the ISN badging process.

  This control was enhanced with mitigation CNTSI-M017 to identify safety training in addition to OSHA required training for contractors and PG&E employees overseeing contractors to ensure they have the appropriate qualifications and training required to oversee the work from a safety perspective and was updated in early 2023 to "Develop a process to validate, in the field, the contractors training compliance with PG&E required training through the use of the ISN badging process". This foundational control and its subsequent enhancements are included in the Contractor Safety Oversight and Compliance Program (CNTSI-PRGB);
- **CNTSI-C021 – Automated System for Improving Processes through ISN:** is a foundational system for the tracking, trending, and generating reports to improve processes through ISN, but does not directly reduce the consequences or reduce the likelihood of risk event; and
- **CNTSI-M015 – The Contractor Safety Handbook:** is a foundational enhancement of CNTSI-C001 (Enhanced Standard Contract Terms and Conditions). The handbook supplements PG&E standard contract terms and conditions with a source of additional guidance on programs, procedures, and other documents that explain PG&E's requirements

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16 See Exhibit (PG&E-2), Chapter 2, Section D.4.g.

and expectations for contractors. The use of handbook is being implemented in 2024.

D. 2027-2030 Proposed Control and Mitigation Plan

1. Changes to Controls

There are two control programs described above that continue through the years 2027 through 2030: Contractor Pre-qualification (CNTSI-PRGA) and Contractor Safety Oversight and Compliance (CNTSI-PRGB) which both include a series of individual controls or measures as mentioned in the Controls section above and as shown in Table 1-9 below. Control CNTSI-C006 – FA Contractor Safety Oversight including Field Safety Observations and HECA is shared with the Employee Safety Incident risk and is included separately for this reason.

Table 1-10 on the following page shows the costs estimates, risk reduction and CBRs for the control programs planned for the 2027-2030 period.

TABLE 1-9
2027-2030 CONTROL PROGRAMS

CNTSI-PRGA	Contractor Pre-Qualification Program	CNTSI-C001 – Enhanced Standard Contract Terms and Conditions CNTSI-C002 – Contractor Safety Pre-Qualifications
CNTSI-PRGB	Contractor Safety Oversight and Compliance	CNTSI-C003 – Contractor Safety Standard and FA (previously LOB) Contractor Oversight Procedures CNTSI-C004 – Contractor Safety Plans CNTSI-C005 – Contractor Hazard Analysis CNTSI-C007 – FA (previously LOB) Compliance Assessments CNTSI-C008 – Corrective Action Program (CAP) for Contractor Issues CNTSI-C009 – Contractor Post Job Safety Performance Review CNTSI-C010 – SIF Incident Governance and Oversight CNTSI-C011 – Contractor Safety Officer Criteria CNTSI-C012 – Cause Evaluation Standard and procedures CNTSI-C013 – ISN Rapid Growth Tracking and Contractor Evaluations CNTSI-C014 – In field training visibility through ISN Individual Badge Feature (foundational) CNTSI-C015 – Standardized Safety Plan and Job Safety Analysis Templates CNTSI-C018 - FA (previously LOB) to Conduct Contractor Forums CNTSI-C019 - Contractor Safety Program Orientation CNTSI-C020 - Enhance Contractor Post Job Performance Evaluation CNTSI-C021 - Automated System for Improving Processes through ISN (foundational) CNTSI-C022 - Contractor Field Safety Observations CNTSI-C023 - Contractor Near-hits/Good-Catches (to be added in 2030 YE) CNTSI-C024 - Contractor Safety Officer Criteria (to be added in 2030 YE) CNTSI-C025 – SIF Capacity and Learning Model (to be added in 2029) CNTSI-C026 - Contractor Safety QA Reviews (to be added in 2030 YE)
CNTSI-C006	FA Contractor Safety Oversight including Field Safety Observations and High Energy Controls Assessments (HECA)	CNTSI-C006 – FA (previously LOB) FA Contractor Safety Oversight including Field Safety Observations and High Energy Controls Assessments (HECA)

TABLE 1-10
CONTROLS COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030

Line No.	Control ID	Control Name	Thousands of Nominal Dollars 2027	2028	2029	2030	Millions of Dollars (NPV)[a] Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[b] [C]/([A]+[B]
1	CNTSI-PRGA	Contractor Pre-Qualification	$205	$210	$215	$221	$0.6	–	$21.5	36.6
2	CNTSI-PRGB	Contractor Safety Oversight and Compliance	$1,230	$1,261	$1,292	$1,325	$3.5	–	$30.2	8.6
3	CNTSI-C006	FA Contractor Safety Oversight including Field Safety Observations and High Energy Controls Assessments (HECA)	$1,479	$1,516	$1,554	$1,593	$4.2	–	$30.2	7.1
4		Total	$2,914	$2,987	$3,062	$3,138				

(a) NPV uses a base year of 2023.

(b) CBR calculations include allocated Foundational Activity Program costs

For additional details see Exhibit (PG&E-7), WP EHS-CNTSI-F.

The cost estimates in this table are generally based on PG&E’s 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

2. Changes to Mitigation

There are two mitigations started in the 2024–2026 period that continue into the years 2027 through 2030 (CNTSI-M019 and CNTSI-M020). Three mitigations included in the 2024-2026 period continue to be operationalized as controls (CNTSI-M012b, M015, and M018). The Contractor Safety Handbook (mitigation CNTSI-M015) is a foundational enhancement of CNTSI-C001 (Enhanced Standard Contract Terms and Conditions).

Table 1-11 below shows the cost estimates, risk reduction and CBRs for the mitigation work planned for the 2027-2030 period.

TABLE 1-11
MITIGATIONS COST ESTIMATES, RISK REDUCTION, CBR, AND FACTORS AFFECTING SELECTION
2027-2030

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[b]				
Line No.	Mitigation ID[a]	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR [c] [C]/([A]+[B])	Factors Affecting Selection
1	CNTSI-M012b	Contractor Near-Hits and Good Catches	$103	$105	$108	$110	$0.3	–	$0.4	1.2	–
2	CNTSI-M018	Contractor Safety Officer Criteria	$103	$105	$108	$110	$0.3	–	$1.2	4.1	–
3	CNTSI-M019	Contractor Safety Quality Assurance Reviews	$300	$300	$300	$300	$0.8	–	$3.7	4.5	–
4	CNTSI-M020, EMPSI-M020	SIF Capacity & Learning Model[c]	$80	$82	–	–	$0.1	–	$1.4	12.1	–
5		Total	$586	$592	$516	$520	–				

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.
(b) NPV uses a base year of 2023.
(c) CBR calculations include allocated Foundational Activity Program costs
For additional details see Exhibit (PG&E-7), WP EHS-CNTSI-F.
The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

Based on the results of the risk modeling analysis shown in Table 1-11 above, PG&E is proposing to spend 2027-2030 funds on the following Contractor Safety Programs: Contractor Near-Hits and Good Catches, Contractor Safety Officer Criteria, Contractor Safety QA Reviews, and the SIF Capacity and Learning model.

E. Alternative Mitigations Analysis

In addition to the proposed mitigations described in Section E above, PG&E considered alternative mitigations as well. The mitigations described in Section E constitute the Proposed Plan. The Alternative Plans consist of a combination of some or all the proposed mitigations along with the alternative mitigation(s). PG&E describes each of the alternative mitigations it considered below and then provides a table showing the forecast costs, CBRs and risk reduction scores for each of the Alternative Plans.

1. Alternative Plan 1: CNTSI-A001 – Contractor Incident Management Tool

This alternative addresses a process inefficiency in the way PG&E designs Corrective Actions. Each PG&E FA safety team manages contractor incidents on a unique and independent platform, relying on archaic methods and individual personnel to create databases and dashboards. When an incident occurs in the field, a contractor copies a template from a Word document into an Outlook email and manually fills out the information, often resulting in the wrong or outdated template version being used. Once PG&E receives this email, it is manually transcribed into Excel spreadsheets and converted into corresponding dashboards. These templates and spreadsheets are unique to each FA: Gas, Electric (Distribution/Transmission/Substation), VM, System Inspection, etc.

Once the notification of an incident is received, each FA uses their own process for investigation, including preparing a Cause Evaluation, establishing Corrective Actions, and conducting an Effectiveness Review. This has resulted in final incident reports of various levels of completeness or effectiveness.

PG&E assumes a 0.5 percent reduction in total number of contractor incidents per year, including those that result in a SIF Actual or SIF

Potential, given the additional Full-Time Equivalent (FTE) hours available to conduct field safety observations (at-risk behaviors) and Contractor assessments. Hours made available for field safety work with the implementation of the Contractor Incident Management Tool are estimated as 3000 hours per year (1.56 FTEs). This alternative was not chosen due to the additional funding needed for an Enterprise-wide software platform and to implement the program. (Table 1-12).

TABLE 1-12
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[(a)]		
Line No.	Mit. No.	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	CNTSI-A001	Contractor Incident Management Tool	$210	$210	$210	$210	$0.6	$0.6	1.0
2		Total	$210	$210	$210	$210	–	–	–

(a) NPV uses a base year of 2023.

For additional details see Exhibit (PG&E-7), WP EHS-CNTSI-F.

The cost estimates in this table are generally based on PG&E’s 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

2. Alternative Plan 2: CNTSI-A002 – In Cab Cameras for Contractors

This alternative involves the development and implementation of a program to require contractors use in-cab camera technology to promote greater driver engagement. Contractors would bear the cost of installation and monitoring of the cameras. 2024 RAMP report costs estimated are based on an FTE overseeing the program only. Mitigation effectiveness would be based on effectiveness results of the technology with co-workers. This alternative was not chosen due to the additional funding needed to implement the program including costs to install cameras in contract partner vehicles which have not been included. In addition, the effectiveness of this mitigation is contingent on the use of this technology in co-worker vehicles which is being implemented in 2024 (Table 1-13).

TABLE 1-13
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030

			Thousands of Nominal Dollars				Millions of Dollars (NPV) [a]		
Line No.	Mit. No.	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	CNTSI-A002	Contractor Safety – In Cab Cameras for Contractors	$171	$171	$171	$171	$0.0	$0.0	TBD[b]
2		Total	$171	$171	$171	$171			

(a) NPV uses a base year of 2023.

(b) Contingent on results of the technology with PG&E coworkers.

For additional details see Exhibit (PG&E-7), WP EHS-CNTSI-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

PACIFIC GAS AND ELECTRIC COMPANY
RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 2
RISK ASSESSMENT AND MITIGATION STRATEGY:
CYBERSECURITY RISK EVENT

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RISK ASSESSMENT AND MITIGATION STRATEGY: CYBERSECURITY RISK EVENT

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PACIFIC GAS AND ELECTRIC COMPANY
RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 2
RISK ASSESSMENT AND MITIGATION STRATEGY: CYBERSECURITY RISK EVENT

A. Introduction

Cybersecurity Risk is defined as a coordinated malicious attack targeting Pacific Gas and Electric Company's (PG&E) core business functions, resulting in disruption or damage of systems used for gas, electric and/or business operations. In the context of PG&E those systems include both Information Technology (IT) and Operational Technology (OT) systems, and assets supporting them. The loss of availability of both IT and OT systems and devices poses a significant risk to our customers and the public; to our employees; to the company and its operations; and to California and the nation.

The cybersecurity threat landscape is not a predictable environment; it is fluid and growing year over year. Our adversaries are becoming more sophisticated in their Tactics, Techniques, and Procedures (TTP), and introducing new malicious payloads which require PG&E's Cybersecurity organization to constantly evolve in both Controls and Mitigations. This situation is compounded by the number of exploitable targets in PG&E.

PG&E's exposure to these potential attacks is measured in 'units of exposure' or Exposure Points. These represent the various targets of an attack coming from one of the attack vectors (Bow Tie drivers). The total number of PG&E Exposure Points is currently calculated at 270,900 but continues to grow and evolve as new technologies are introduced to PG&E. These Exposure Points are categorized as Network Segments; IT and OT systems and devices; PG&E employees, contractors and third parties currently doing business with PG&E; and software (commercially off-the-shelf (COTS) products and custom developed systems). The scope of the potential targets has informed the identification of the Cybersecurity Risk Bow Tie drivers which represent the attack vectors by which adversaries will attempt to execute a successful attack. These drivers include Social Engineering, Malware/Ransomware, Software and Application Defects, Vulnerable Devices and Infrastructure, Supply Chain, and

Insiders (malicious and inadvertent). The potential impact from a successful coordinated cybersecurity attack on PG&E can be significant.

Cybersecurity risk event has the eighth-highest 2027 Test Year (TY) Baseline Safety Risk Score ($24.8 million) and the fourth-highest 2027 TY Baseline Total Risk Score ($1.0 billion) of PG&E's 32 Corporate Risk Register risks.

1. Risk Overview

Table 2-1 below captures the risk definition and scope and data sources used for quantification.

TABLE 2-1
RISK DEFINITION, SCOPE, AND DATA SOURCES

Line No.	Risk Name	Cybersecurity Risk Event
1	Definition	A coordinated malicious attack targeting PG&E's core business functions, resulting in disruption or damage of systems used for gas, electric and/or business operations.
2	In Scope	PG&E IT and OT systems and infrastructure assets supporting PG&E's mission and business model.
3	Out of Scope	Internal systems and infrastructure managed by the Nuclear functional area for Diablo Canyon Nuclear Power Plant (DCPP). IT-managed systems and devices supporting DCPP are within scope.
4	Data Quantification Sources	Internal PG&E Security Intelligence Operations Center (SIOC) monitored attacks and incidents, US utility industry attack statistics, Federal Intelligence reports, and cybersecurity claims data.

PG&E's Cybersecurity organization is solely focused on the identification, quantification, and mitigation of cybersecurity risk to PG&E, current and evolving. The Cybersecurity organization is a proactive, future-leaning, risk-centric group whose mission is to reduce the cybersecurity risk profile to PG&E, its customers, and the State of California. The organization and its people, processes and technologies are aligned to the NIST Cybersecurity Framework (CSF) (Identify, Protect, Detect, and Respond (Recover is a function of the Enterprise Preparedness and Response organization and partners closely with our Disaster Recovery Team and all Functional Areas)) and informed by the NIST SP 800-37 Risk Management Framework.

B. Risk Assessment

1. Background and Evolution

The cybersecurity risk assessment processes and resulting risk models, controls and mitigations have continued to evolve to reflect the changes in the cyber threat landscape. These changes and continuing evolution are reflected in the changes to the Cybersecurity Bow Tie, evolving from a cross cutting model in 2020 to a standalone risk in 2021, currently rated as 8th safety risk and the 4th overall risk to PG&E. While the Cybersecurity event is now recognized as a standalone risk, a cyber-attack can impact other functional area risks, so cybersecurity is also recognized as a cross-cutting factor. The continued refinement of the risk model has now elevated the cybersecurity risk to the #4 TY 2027 Baseline risk to PG&E.

The PG&E Cybersecurity organization is aligned to NIST, both at a strategic and tactical level. This includes using the NIST CSF, the NIST prioritized administrative and technical/logical controls (NIST SP 800-53 R5), and the NIST Risk Management Framework (SP 800-37). This baseline provides a unified approach to cybersecurity and cyber risk management. This alignment provides an optimized approach to risk identification, evaluation, rating, and mitigations which has provided the foundation for an adaptative and scalable risk management practice. This alignment also provides the ability to effectively maintain current defenses to mitigate the cyber-attacks via the Risk Assessment and Mitigation Phase (RAMP) Cybersecurity Bow Tie risk drivers and to prevent the potential cyber-attack consequences. However, as previously stated, PG&E Cybersecurity is in constant need of updating its cybersecurity defenses and organizational capabilities to stay positioned to address emerging threats. The ever-evolving cybersecurity threat landscape has required PG&E Cybersecurity to constantly re-evaluate risk and evolve accordingly. The Cybersecurity strategy focus to address these evolving risks is depicted in Table 2-2, Cybersecurity Strategy Focus 2023-2028.

TABLE 2-2
CYBERSECURITY STRATEGY FOCUS 2023-2028

Line No.	Strategy Focus Areas	Description
1	Zero Trust Architecture	The basis of a zero-trust architecture and environment is the knowledge that applications, systems, and infrastructure cannot be trusted and require enhanced architecture and continuous monitoring. PG&E is aligning the assessment of the practice to NIST SP 800-207 (Zero Trust Architecture).
2	OT and Industrial Control Systems (ICS)	As the OT and ICS systems and environments continue to evolve with new functionality and communication methods, the threat landscape and cyber adversaries continue to accelerate in numbers and sophistication of attacks.
3	Cloud Security	The continued use of cloud-based environments to support a wide range of IT and OT/ICS systems and infrastructure requires an ever-evolving strategy to stay current, and proactively ahead of the evolving cyber threats.
4	Mobile Device	The proliferation of mobiles devices, their increasing importance to any business operations, evolution of the devices, and the constant updates to operating systems requires a strategy to keep pace with the potential cyber threats.
5	Grid Edge	The continued expansion of Distributed Energy Systems and the grid edge boundary (customer owned systems, hardware, and equipment) requires an evolving strategy to monitor and protect against cyber threats originating from non-utility managed boundary devices and infrastructure.
6	Artificial Intelligence (AI)	The rapid evolution and adoption of AI by the industry and cyber threat actors continues to have a significant impact on proactive risk mitigation strategies. This requires PG&E to continuously reevaluate the threat landscape and existing controls and mitigations to proactively plan for the accelerating risk exposure.

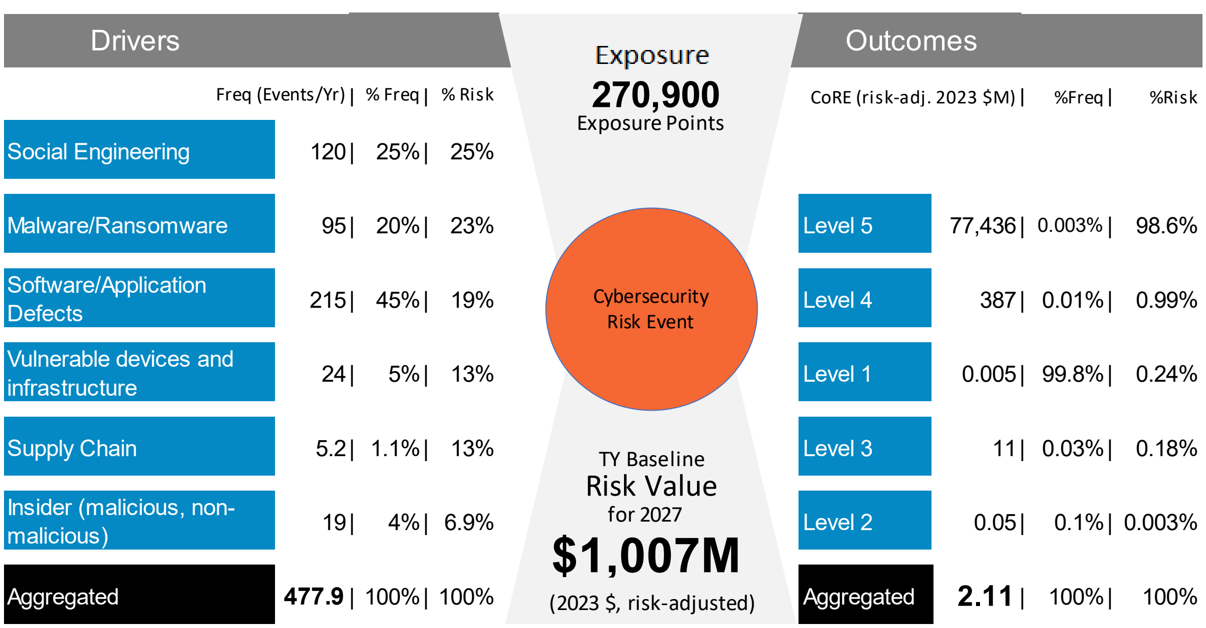
2. Risk Bow Tie

The PG&E Cybersecurity Bow Tie reflects the enterprise cybersecurity risk to PG&E and is represented by four key components: Tranches, Drivers, Exposure Points, and Outcomes. The drivers represent the ways (attack vectors) a threat actor could successfully launch a cyber-attack, the exposure points represent the attack surface (applications, systems, assets, people, and vendors), and outcomes represents the possible negative result/impact from a successful cyber-attack. Within these four key components there are other factors represented, such as the frequency of attacks via a specific driver, probability of an attack causing a negative outcome, and the impact of an attack risk of a cyber-attack causing a certain level outcome. These components together represent an aggregated enterprise cybersecurity risk posture.

TABLE 2-3
CYBERSECURITY BOW TIE CONSTRUCTS

Line No.	Bow Tie Component	Description
1	Tranches	A logical disaggregation of a group of assets (physical or human) or systems into subgroups with like characteristics for purposes of risk assessment. The Tranches contribute to the total Exposure Point count in the Bow tie.
2	Drivers	Factor(s) that could cause one or more risks to occur (Risk driver may also be commonly referred to as “threat”).
3	Exposure Points	Represents the various targets of an attack coming from one of the attack vectors (Bow Tie drivers).
4	Impact/ Consequences	The effect or outcome of an event affecting objectives, which may be expressed by terms including, although not limited to health, safety, reliability, economic and/or environmental damage.

FIGURE 2-1
RISK BOW TIE



3. Exposure to Risk

PG&E's exposure to Cybersecurity Risk is measured in 'units of exposure' or Exposure Points. These represent the various targets of an attack coming from one of the attack vectors (Bow Tie drivers). The total number of PG&E Exposure Points is currently calculated at 270,900 but continues to grow and evolve as new technologies are introduced to PG&E. These Exposure Points are categorized as Network Segments; IT and OT systems and devices; PG&E employees, contractors and third parties currently doing business with PG&E; and software (commercially off-the-shelf (COTS) products and custom developed systems).

The capabilities and motivation by threat actors for a cyber-attack change and increase frequently. As previously mentioned, PG&E is a prime target for threat actors, both, threat actors trying to extort PG&E financially as well as those politically motivated looking to impact critical infrastructure and disrupt PG&E's ability to provide energy to its customers. These two motivations are distinct and the type of damage/disruption they aim to cause varies. Due to the distinct nature of motivations, PG&E's threat actors could be Nation States, Insiders, Organized Crime, or Hacktivists. PG&E's units of exposure are divided into tranches and discussed in the following section.

4. Tranches

The Tranches represent the broad classification of the threat actor targets which represents our attack surface. PG&E identified five tranches which are represented in the risk model Bow Tie. These tranches are described in Table 2-4:

TABLE 2-4
TRANCHE SUMMARY

Line No.	Tranche	Tranche Description
1	Utility Data Network (UDN)	PG&E's primary network which carries the most traffic and data and has the most users of PG&Es business systems. It is the network where PG&E conducts most of its daily business. As such, it could serve as an entry point for threat actors and UDN systems and devices are quantified to be represented as the node counts in the Bow Tie.
2	The Operational Data Network (ODN)	This network carries the traffic and data supporting the operational functions of PG&E. The ODN contains data, systems and OT technologies that are core to the generation and distribution of energy to our customers. OT systems are the primary target of nation state threat actors as an impact to the ODN could potentially cause the most disruption to PG&E and its customers. ODN systems and devices are quantified to be represented as the node counts in the Bow Tie.
3	Third Parties	Represent anyone or any entity that provides goods, services and or has access to PG&E network or data. These are vendors and business partners that for business reasons need access to our data and our network and are quantified as the third-party count in the Bow Tie.
4	People	Represent both internal employees and contractors at PG&E. They are quantified as people in the Bow Tie.
5	Software/Applications	The computer programs (COTS and custom developed) that employees and contractors use every day. Software is particularly susceptible to programing flaws, vulnerabilities and one of the vectors threat actors use to cause a cybersecurity event.

5. Drivers and Associated Frequency

Drivers represent the attack vectors, techniques, and ways that a threat actor could use to initiate and or deliver a payload to access and/or destroy PG&E systems and data. There are six classifications of drivers: Malware/Ransomware, Supply Chain, Social Engineering, Insider Threat, Vulnerable Devices and Infrastructure, and Software/Application Defects. The Cybersecurity Bow Tie Drivers and related potential incidents are identified in Table 2-5 Bow Tie Cybersecurity Attack Vectors.

TABLE 2-5
BOW TIE CYBERSECURITY ATTACK VECTORS

Line No.	Bow Tie Drivers	Cybersecurity Incident
1	Social Engineering	Social engineering is the tactic of manipulating, influencing, or deceiving a victim to gain control over a computer system, or to steal personal and financial information.
2	Malware/ Ransomware	A payload (malicious software) developed by cybercriminals to steal data and damage or destroy computers and computer systems.
3	Software/ Application Defects	Inadvertent or purposely built-in vulnerabilities (back doors) that threat actors can use to gain access to systems and networks.
4	Vulnerable devices and infrastructure	A vulnerability (unpatched systems, unsupported OS, etc.) that a threat actor can exploit to gain access to systems and networks.
5	Supply Chain	A value-chain or third-party attack occurs when someone infiltrates your system through an outside partner or provider with access to your systems and data.
6	Insider Attack	A malicious or inadvertent action that results in penetration of systems or networks, or an exfiltration of data.

6. Cross-Cutting Factors

A cross-cutting factor is a driver, component of a driver, or a consequence multiplier that impacts multiple risks. PG&E is presenting seven cross cutting factors in the 2024 RAMP. The cross-cutting factors that impact the Cybersecurity risk event are shown in Table 2-6 below.

Cybersecurity risk is unique in that it can be the root cause of a disruption/impact to another functional area within PG&E and can be impacted by an impact/disruption to another functional area.

A threat actor could use a cyber-attack to disrupt energy (electric and gas) delivery to customers. Threat actors could also try to cause an asset failure (such as a firewall) and due to that asset (firewall) not working as intended gain unauthorized access to PG&E data and or computer systems. This is covered more in depth in Exhibit (PG&E-2), Chapter 3.

TABLE 2-6
CROSS-CUTTING FACTOR SUMMARY

Line No.	Cross-Cutting Factor	Impacts Likelihood	Impacts Consequence
1	Climate Change	No	No
2	Cyber Attack	No	No
3	EP&R	No	Yes*
4	Information Technology Asset Failure	Yes*	Yes*
5	Physical Attack	Yes*	Yes*
6	Records and Information Management (RIM)	Yes*	Yes
7	Seismic	No	No

Yes The cross-cutting factor has been quantified in the model.

Yes* The cross-cutting factor does influence the baseline risk but has not been quantified in the model, or the cross-cutting factor may influence the baseline risk but further study is needed.

No The cross-cutting factor does not meaningfully influence the baseline risk.

A description of the cross-cutting factors and the mitigations and controls that PG&E is proposing to mitigate the cross-cutting factors is in Exhibit (PG&E-2), Chapter 3.

7. Consequences

The Consequences represent the range of possible outcomes/impacts due to a successful cyber-attack. The impacts range from minor to catastrophic. An example of a minor event would be clicking on a link that contains malware and that event being contained to that computer system with no other impacts. On the other side of the consequence scale is a catastrophic event, which could lead to a material financial loss, the inability to reliably provide gas or electricity to PG&E customers as well as potential direct and or indirect safety consequences. The consequences are identified in Table 2-7 Risk Model Consequence Summary.

TABLE 2-7
RISK MODEL CONSEQUENCE SUMMARY

Consequences

	CoRE	%Freq	%Risk	Freq	Natural Units Per Event					Monetized Levels (2023 $M) of a Consequence Per Event					CoRE (risk-adj 2023 $M/event)				
					Safety	Indirect Safety	Electric Reliability	Gas Reliability	Financial	Safety	Indirect Safety	Electric Reliability	Gas Reliability	Financial	Safety	Indirect Safety	Electric Reliability	Gas Reliability	Financial
					EF/event	EF/event	MCMI/event	#cust/event	$M/event	$M/event	$M/event	$M/event	$M/event	$M/event	$M/event	$M/event	$M/event	$M/event	$M/event
Level 5	77,436	0.003%	98.6%	0.01	0.05	23	3,735	183,654	802	0.8	344	11,840	288	802	1.4	1,934	71,387	1,964	2,149
Level 4	387.5	0.01%	1.0%	0.03	-	-	-	-	197	-	-	-	-	197	-	-	-	-	387
Level 1	0.005	99.8%	0.2%	477.0	-	-	-	-	0.005	-	-	-	-	0	-	-	-	-	0
Level 3	11	0.03%	0.2%	0.2	-	-	-	-	8.977	-	-	-	-	8.98	-	-	-	-	10.95
Level 2	0.05	0.13%	0.003%	0.6	-	-	-	-	0.05	-	-	-	-	0.05	-	-	-	-	0.05
Aggregated	2.11	100%	100%	477.9	0.000001	0.001	0.100	4.9	0.040	0.00	0.01	0.32	0.01	0.0	0.00004	0.05	1.92	0.05	0.1

	Natural Units per Year					Expected Loss per Year (2023 $M)					Attribute Risk Score (risk-adj 2023 $M)				
	Safety	Indirect Safety	Electric Reliability	Gas Reliability	Financial	Safety	Indirect Safety	Electric Reliability	Gas Reliability	Financial	Safety	Indirect Safety	Electric Reliability	Gas Reliability	Financial
	EF/yr	EF/yr	MCMI/yr	#cust/yr	$M/yr	$M/yr	$M/yr	$M/yr	$M/yr	$M/yr	$M/yr	$M/yr	$M/yr	$M/yr	$M/yr
Level 5	0.00	0.3	47.9	2,354.6	10	0.01	4.4	151.8	3.7	10	0.02	24.8	915.2	25.2	28
Level 4	-	-	-	-	5	-	-	-	-	5	-	-	-	-	10
Level 1	-	-	-	-	2.4	-	-	-	-	2.4	-	-	-	-	2.4
Level 3	-	-	-	-	1.50	-	-	-	-	1.5	-	-	-	-	1.8
Level 2	-	-	-	-	0.03	-	-	-	-	0.03	-	-	-	-	0.03
Aggregated	0.0006	0.29	47.89	2,354.6	19	0.01	4.41	151.80	3.7	19.28	0.02	24.79	915.24	25.19	41.76

C. 2023-2026 Control and Mitigation Plan

Tables 2-8 and 2-9 list the controls and mitigations PG&E included in its 2020 RAMP and 2023 GRC and is including in this 2024 RAMP (2024-2026 and 2027-2030). The tables provide visibility on the status of controls and mitigations (e.g., whether they are on-going or no longer in place) as well as changes to controls and mitigations.

In the following sections PG&E describes the controls and mitigations in place during the 2023-2026 period. PG&E then discusses new mitigations and/or significant changes to mitigations and/or controls during the 2027-2030 periods.

TABLE 2-8
PG&E CYBERSECURITY CONTROLS SUMMARY

Line No.	Control Number and Name[a]	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2024-2026)	2024 RAMP (2027-2030)
1	Control 1 – Security Intelligence and Operations Center	X	Becomes CYBER-C001		
2	Control 2 – Cybersecurity Risk and Strategy	X	Becomes CYBER-C002		
3	Control 3 – Cybersecurity Services	X	Becomes CYBER-C003		
4	Control 4 – Communications	X	Becomes CYBER-C004		
5	Control 5 – Investigation and Insider Threats	X	Combined into CYBER-C001		
6	CYBER-C001 – Security Intel/Ops Center		X	X	X
7	CYBER-C002 – Cybersecurity Risk/Strategy		X	X	X
8	CYBER-C003 – Cybersecurity Services		X	X	X
9	CYBER-C004 – Governance/ Compliance		X	X	X

(a) Controls included in the 2020 RAMP do not start with CYBER, distinguishing between Control Numbers used in the 2020 RAMP Report and Control Numbers used in the 2023 GRC and 2024 RAMP.

TABLE 2-9
PG&E CYBERSECURITY MITIGATIONS SUMMARY

Line No.	Mitigation Number and Name [(a)]	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2024-2026)	2024 RAMP (2027-2030)
1	M1 – Identify	X	Becomes CYBER-M001		
2	M2 – Protect	X	Becomes CYBER-M002		
3	M3 – Detect	X	Becomes CYBER-M003		
4	M4 – Respond	X	Becomes CYBER-M004		
5	CYBER-M001 – Identify		X	X	X
6	CYBER-M002 – Protect		X	X	X
7	CYBER-M003 – Detect		X	X	X
8	CYBER-M004 – Respond		X	Rolls into CYBER-M003	Rolls into CYBER-M003

(a) Mitigations included in the 2020 RAMP does not start with CYBER, distinguishing between Mitigation Numbers used in the 2020 RAMP Report and Mitigation Numbers used in the 2023 GRC and 2024 RAMP.

1. Controls

The PG&E Controls are categorized and linked to the PG&E Cybersecurity programs focused on Cybersecurity risk identification and management. These controls are represented financially by the PG&E cybersecurity baseline (expense only) and Operations and Maintenance (O&M) expenditures. These four RAMP controls are identified in Table 2-9, PG&E Cybersecurity Controls.

These risk management controls are focused on the identification, assessment, and development of mitigation strategies to address the cybersecurity threats identified in the cybersecurity Bow Tie (Drivers). Each control has a common risk mitigation mission and strategy to provide cybersecurity protection, however, they have different tactical focuses (mitigations) and contributions to risk management. Specifically, these organization-specific risk management functions provide:

- **CYBER-C001 – Security Intel/Ops Center:** The SIOC is responsible for event monitoring and incident response as well as threat intelligence and penetration testing. Within the SIOC there are several activities including:

- eDiscovery and Digital Investigations;
- Pen Testing and Data Security;
- Cyber Threat Intelligence; and
- Threat Detection and Response.

- **CYBER-C002 – Cybersecurity Risk and Strategy:** This Control is focused on the end-to-end management of cybersecurity risk. Cybersecurity Risk and Strategy also has the responsibility for the reporting of risk to the executive level and the maintenance of the cybersecurity risk management strategy as well as the development and updating of PG&E policies and utility standards. Within the program, there are several activities including:
  - Enterprise Cyber Risk Management;
  - Third Party Security;
  - Control Metrics and Reporting (primarily focused on vulnerability Management);
  - Cyber Solutions (focused on tactical risk assessment activities, project, and production systems); and
  - Business Cybersecurity Risk Management (a liaison organization to the Functional Areas).
- **CYBER-C003 – Cybersecurity Services:** This control is primarily focused on the operational nature of cybersecurity and includes cybersecurity engineering and architecture responsibilities. Within the Cybersecurity Solutions division there are several activities including:
  - Security Controls and Infrastructure;
  - Identify and Access Management;
  - Network Protection Services;
  - Cloud Security Center of Excellence; and
  - Cybersecurity Architecture and Engineering.
- **CYBER-C004 – Governance and Compliance:** This control is focused on developing and maintaining the PG&E Governance Document Library which contains all the PG&E Policies and Utility Standards and performing cybersecurity compliance to standards activities. The Governance and Compliance program also manages and tracks the risk mitigation activities to completion.

2. Mitigations

The 2023 risk mitigations are categorized by PG&E Cybersecurity programs, from which activities align with the Categories of the NIST CSF program Identify, Protect, Detect and Respond. The specific mitigation items are not described here due to the cybersecurity risk of releasing the information to the public. A detailed listing of the tools and internal cyber process would provide information to PG&E's adversaries and would weaken PG&E's cybersecurity defenses and enable the development of a roadmap to attack PG&E. PG&E is providing a high-level summary for each mitigation program to describe how the mitigation addresses the cybersecurity risk identified in the 2023 Cybersecurity Risk Event Bow Tie, i.e., how the mitigation relates to the Drivers and potential Consequences. The 2023 Cyber mitigation categories are:

- Cyber Risk Management;
- Cyber ODN Security;
- Cyber Transportation Security Administration Security Directive;
- Cyber Penetration Testing;
- Cyber Configuration and Vulnerability;
- Cyber Cloud Security and Directory Services;
- Cyber Endpoint and Data Protection;
- Cyber Intelligence and Event Management;
- Cyber Identity and Access Management;
- Enterprise Mobility Security; and
- Cyber Asset Management (Completeness of IT/OT Asset Inventory).

Table 2-10 below shows the forecast expense costs for the mitigation work planned for the 2024-2026 period while Table 2-11 provides the capital costs for the mitigation work planned for the 2024-2026 period. Following Tables 2-10 and 2-11 are summary descriptions of the mitigations for 2023-2026.

TABLE 2-10
MITIGATION COSTS ESTIMATES
2024-2026 EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Mitigation ID	Mitigation Name	2024	2025	2026	Total
1	CYBER-M001	Identify	$500	$707	$686	$1,892
2	CYBER-M002	Protect	2,745	3,710	3,916	10,370
3	CYBER-M003	Detect	900	1,142	1,216	3,258
4		Total	$4,145	$5,558	$5,818	$15,521

Note: For additional details see workpaper (WP) IT-CYBER-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

TABLE 2-11
MITIGATION COSTS ESTIMATES
2024-2026 CAPITAL
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Mitigation ID	Mitigation Name	2024	2025	2026	Total
1	CYBER-M001	Identify	$1,581	$3,871	$4,212	$9,664
2	CYBER-M002	Protect	20,700	22,790	24,054	67,544
3	CYBER-M003	Detect	6,402	7,014	7,473	20,888
4		Total	$28,683	$33,675	$35,739	$98,097

Note: For additional details see Exhibit (PG&E-7), WP IT-CYBER-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3

Due to cybersecurity risk considerations, the specific mitigations descriptions have been aggregated and summarized.

The 2023-2026 forecast Cyber Mitigations summaries are as follows:

- **CYBER-M001 – Identify:** The specific mitigations associated with the mitigation classification M001 are as follows:
  - **Cyber Risk Management –** In addition to the ongoing mitigation, PG&E risk management mitigations will include AI Security and Governance, Avionics Security, EV Cyber risk mitigation, Cyber risk and supply chain risk management, an integrated risk management platform, and Development Security Operations (DevSecOps) enhancements.

- **Cyber Asset Management (Completeness of IT/OT Asset Inventory)** – Mitigation for the activities to address completeness of IT/OT Asset Inventory include further identifying unknown OT, IT and physical facility assets with central oversight or cyber monitoring to mitigate the exposure to increasing cyberattack and compliance risk.
- **Third Party Risk** – The Third Party Risk mitigations will enhance PG&E's ability to process a greater volume of third-party risk assessment in a more efficient manner while at the same time providing greater efficacity of results.
- **IT Compliance** – Enhanced Compliance mitigations will allow for the unification of compliance activities and focus across the PG&E Functional Areas. Specifically, this will include changes to utility standards to reflect the risk of AI security.
- **Securities and Exchange Commission (SEC) Compliance Requirements** – In 2024, PG&E will implement a plan to enhance our ability to comply will the new laws and regulatory requirements from the SEC's final cybersecurity disclosure rules. This will allow us to report material cybersecurity incidents to the SEC within the mandated four business days.

• **CYBER-M002 – Protect:** The specific mitigations associated with the mitigation classification M002 are as follows:

- **Cyber Network Protection** – The Network Protection mitigations employ a variety of security technologies that support PG&E's network security architecture across all NIST pillars: Identify, Protect, Detect, Respond, Recover. They provide protection for network/systems infrastructure as well as for PG&E applications and services. Network protection at PG&E relies heavily on technologies to provide secure/reverse proxy capabilities, web application firewall capabilities, traffic visibility, Distributed Denial of Service (DDoS) mitigation capabilities, network firewall capabilities, threat prevention, URL filtering, VPN capabilities, user/identity-based policy enforcement, etc.

- **Cyber Configuration and Vulnerability** – The Cyber Configuration and Vulnerability management mitigations are responsible for implementing improvements to the Cybersecurity team's ability to monitor, detect, and report on configuration changes across the organization's infrastructure to PG&E critical assets. Capabilities include IT and OT asset and application scanning to detect vulnerabilities and out of compliance configuration changes throughout PG&E environments, which in turn informs the Vulnerability Management Program and provides greater visibility to the SIOC of active vulnerabilities and attacks.
- **Cyber Endpoint and Data Protection** – The Endpoint and Data Protection mitigations focus on protecting data stored on PG&E devices from unauthorized access, including data at rest and data in transit, including to other Operating Systems, Networks, External parties, and cloud storage. It includes structured data in databases and unstructured data in our Email communications, Documents, Spreadsheets, Images, and other files, accounting for 80%+ of PG&E's data. Since most unstructured data is on end user devices and can be exposed easily to physical theft, unauthorized sharing, and other threats, they require significant protection, detection, and response capabilities. Anti-malware detects and automatically cleans viruses and other malware attempting to be copied to or executed on all workstations and servers. Advance Threat Protection provides real-time endpoint security to notify, or block known and unknown malware, exploits and zero-day threats.(zero day threats represent potential exploitation of a vulnerability in software or hardware that are not yet known to the developers) Standard encryption deployed on endpoint systems (workstations and laptops), to prevent access to company data should this equipment be lost or stolen.
- **Cyber Cloud Security and Directory Services** – Mitigations will be enhanced to include Cloud Application protection platform and enhancements to the DevSecOps for cloud.

- **Cyber Identity and Access Management (IAM)** – IAM mitigations provide complete visibility and control of access for all PG&E employees, contractors, as well as non-human users including Service Accounts through the electronic access platform and all its components. IAM mitigations also provide security of the SAP system and compliance for Sarbanes-Oxley and North American Electric Reliability Corporation CIP logical access management and provide application integrations for access, including My Electronic Access for identity management, web access, single sign on (SSO) and directory services for externally facing applications and physical security applications.
- **Cyber Privileged Access** – The Directory Services and Privilege Access Management mitigations provides capabilities that work in tandem to manage directory services and privileged access locally and on back-end directory system. This includes central policies in servers, access-based group policies and set up, privileged access brokering, service account management and reporting, password policies, project-based consulting and support to the enterprise, certificate and encryption management, application integrations. Capabilities also include a cloud-based directory for cloud access.
- **ODN Security** – Optimizing the islanding/isolation capabilities for the ODN is the focus on these mitigations. This starts a multiyear journey to achieve an optimal state, requiring assistance from system owners to understand business impacts of various isolation techniques to inform the roadmap.
- **App Integration Enterprise Mobility Security SSO** – The SSO Integrations is for apps to integrate with Enterprise Mobility Security for SSO. The ability to have application users logged into and connected with the Enterprise Mobility Security platform is critical for the utilization of the cybersecurity controls offered by the Enterprise Mobility Security.
- **Security Controls and Infrastructure** – These mitigations are required to enhance technical controls to combat the evolving risk landscape and applies the existing tools and cyber defense

systems. To stay current with, and ahead of the changing threat landscape, the industry is developing new capabilities to identify and mitigate risk. These mitigations address the tactical needs for cyber defense and response and include a focus on Grid Security and Data protection tools.

- **Security Architecture & Engineering** – These mitigations are intended to support the security by design principle, by enhancing our cybersecurity architecture and engineering controls. This will result in enhanced architectural patterns and solutions engineering providing a cybersecurity baseline to guide all PG&E enterprise architecture activities and will also include ODN Islanding, and Zero Trust architecture enhancements.

- **CYBER-M003 – Detect:** The specific mitigations associated with the mitigation classification M003 include efforts associated with the "Detect" and "Respond" domains of NIST CSF, which are managed by the Security Intel/Ops Center function. They include efforts like the following:
  - **Cyber Intelligence and Event Management** – Enhancements to the cybersecurity monitoring and intelligence mitigation will include Zero Trust Security; Cyber Asset and Attack Surface Management (IT/OT/Cloud) and Converged Threat Platform.
  - **eDiscovery and Data Security** – Enhancements to the cybersecurity eDiscovery and data security mitigation to address advanced security threats and evolving threat landscape.
  - **Cyber Penetration Test Findings Remediation** – PG&E conducts annual Penetration Tests that result in findings and recommendations. These mitigation activities are established to enable and manage remediation efforts.

3. Foundational Activities

As discussed in Exhibit (PG&E 2), Chapter 2, foundational activities are programs that enable two or more control or mitigation programs but do not directly reduce the consequences or the likelihood of risk events. As the sole mission and focus of cybersecurity is the identification and mitigation of cybersecurity risk, there are no foundational activities outside of the core

Cybersecurity controls and mitigations. The PG&E cybersecurity controls and mitigations encompass the foundational risk management activities.

D. 2027-2030 Proposed Control and Mitigation Plan

1. Changes to Controls

The cybersecurity controls are projected to remain unchanged for the 2027 to 2030 period. The controls as presently implemented and account for the risk identified in the cybersecurity Bow Tie. Specifically, the controls are aligned with the Bow Tie drivers to address existing and potential cybersecurity risks. The controls are designed to be adaptable to the ever-changing threat landscape and evolving cybersecurity risks.

Table 2-12 shows cost estimates, risk reduction values and CBRs for proposed controls.

TABLE 2-12
CONTROLS COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030 EXPENSE

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[(a)]			
Line No.	Control ID	Control Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[(b)] [C]/([A]+[B])
1	CYBER-C001	Security Intel/Ops Center	$7,653	$7,789	$7,927	$8,068	$21.7	–	$1,089.2	50.2
2	CYBER-C002	Cybersecurity Risk/Strategy	5,058	5,210	5,366	5,527	$14.6	–	$1,657.1	113.6
3	CYBER-C003	Cybersecurity Services	16,424	16,917	17,425	17,947	$47.4	–	$7,442.7	157.1
4	CYBER-C004	Governance/Compliance	3,276	3,374	3,475	3,579	$9.4	–	$1,657.1	175.4
5		Total	$32,411	$33,290	$34,193	$35,122				

(a) NPV uses a base year of 2023.

(b) CBR calculations include allocated Foundational Activity program costs.

For additional details see Exhibit (PG&E-7), WP IT-CYBER-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

2. Changes to Mitigations

PG&E Cybersecurity has analyzed the emerging risks and has planned on several mitigations to address those risks. For 2027-2030 the established mitigation will continue to have additional tactical approaches to support the mitigation of cyber security risk including evolving current risks, emerging risks and new laws and regulations. As previously stated, PG&E Cybersecurity has generalized detailed risk mitigation spending information due to sensitivity of that information. If exfiltrated, threat actors would use that information to develop attack plans and strategies. Instead, the forecast mitigation costs have been aggregated. Tables 2-13 and 2-14 below shows the cost estimates, risk reduction values, CBRs and factors affecting selection for the mitigation work planned for the 2027 to 2030 period.

While the Protect CBR is calculated at 0.8, it is a key control and mitigation and is integral to supporting the Identify and Detect controls. Protect is critical to Identify control when assessing residual risk and from a Detect control, it can be leveraged to contain an indicator of compromise once detected which then results in respond action to mitigate cybersecurity risk. While the CBR scope is 0.8, the Protect mitigations are integral to addressing emerging risks (e.g., Artificial Intelligence), and as we address emerging risks the impacts can be calculated only after the emerging risks manifest in attacks.

TABLE 2-13
MITIGATIONS COST ESTIMATES, RISK REDUCTION, CBR, AND FACTORS AFFECTING SELECTION
2027-2030 EXPENSE

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[a]				
Line No.	Mitigation ID	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[b] [C]/([A]+[B])	Factors Affecting Selection
1	CYBER-M001	Identify	$730	$911	$828	$870	$23.6	–	$56.5	2.4	
2	CYBER-M002	Protect	4,120	4,755	4,999	5,249	$140.0	–	$113.1	0.8	Risk Tolerance
3	CYBER-M003	Detect	1,296	1,363	1,431	1,502	$41.0	–	$75.1	1.8	
4		Total	$6,146	$7,028	$7,258	$7,621					

(a) NPV uses a base year of 2023.

(b) CBR calculations include allocated Foundational Activity program costs.

For additional details see Exhibit (PG&E-7), WP IT-CYBER-F.

The cost estimates in this table are generally based on PG&E’s 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

TABLE 2-14
MITIGATIONS COST ESTIMATES, RISK REDUCTION, CBR, AND FACTORS AFFECTING SELECTION
2027-2030 CAPITAL

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[a]				
Line No.	Mitigation ID	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[b] [C]/([A]+[B])	Factors Affecting Selection
1	CYBER-M001	Identify	$4,485	$4,777	$5,089	$5,344	$23.6	–	$56.5	2.4	
2	CYBER-M002	Protect	25,307	29,207	30,710	32,245	$140.0	–	$113.1	0.8	Risk Tolerance
3	CYBER-M003	Detect	7,963	8,370	8,789	9,228	$41.0	–	$75.1	1.8	
4		Total	$37,756	$42,354	$44,588	$46,817					

(a) NPV uses a base year of 2023.

(b) CBR calculations include allocated Foundational Activity program costs.

For additional details see Exhibit (PG&E-7), WP IT-CYBER-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

3. Factors Affecting Mitigation Selection

Tables 2-13 and 2-14 summarize PG&E’s proposed mitigations during the 2027-2030 period including the rationale for selecting the Protect mitigation that has a CBR less than 1.0. Additional information on the rationale for selecting the Protect mitigation is provided below. As stated previously, PG&E declines to provide specific details of the mitigations involving people, process, or technologies. If the details of mitigations were to be exfiltrated and examined by our adversaries (threat actors) it would provide a blueprint for how to create a successful cyber-attack with the intent of inflecting maximum catastrophic damage.

- **Risk Tolerance:** The Commission has recognized the need for discussion and clear guidance on Risk Tolerance and has expressed its intention to address this topic in future Phases of the Risk OIR. In the meantime, PG&E’s risk mitigation strategies are selected to ensure that safety remains PG&E’s top priority even when the quantitative RAMP modelling indicates the costs are higher than the modeled value of risk reduction. All Cybersecurity Risk mitigations support the mitigation of a catastrophic cybersecurity event which could result in a serious injury or fatality, including programs under the “Protect” mitigation (with a CBR of 0.8). The following provides additional detail on the importance of the mitigations that current modeling shows have a collective CBR of 0.8:
  - **Network Protection:** The Network Protection mitigations which are part of the Protect mitigation classification, provide defenses against active, ‘in the wild threats’ (currently active attacks) and protection against emerging threats. These mitigations provide cybersecurity logical/technical controls designed to prevent the exfiltration of data, injection of malicious payloads, and network penetration and lateral movement by threat actors. A successful breach of defenses could result in an adverse cybersecurity event with varying consequences up to and including catastrophic impacts and potential for loss of life.
  - **Cyber Endpoint and Data Protection:** The Cyber Endpoint and Data Protection mitigations which are part of the Protect mitigation classification, provide defenses against the exfiltration of confidential and protected data and the identification and neutralization of

malicious payloads that have infected endpoints. The exfiltration of confidential and protected data could affect PG&E and our customers and could result in significant financial penalties, reputational damage, and potentially the safety of our customers. An active malicious payload not identified and stopped could result in significant damage to PG&E and if ransomware in nature could disrupt PG&E business and operations. The impact from a loss of ability to provide our customer with power would have significant and catastrophic consequences including the loss of life.

– **Cyber Cloud Security and Directory Services**: Cyber Cloud Security and Directory Services mitigations are part of the Protect mitigation classification. As more services are being provided by cloud provides, including SaaS, Infrastructure-as-a-Services and Platform-as-a-Service, just to name a few, the attack landscape increases allowing more avenues for cyber-attack (attack vectors). This increases the complexity of keeping data and systems safe and protected. Conversely the more cloud computing serves are utilized, it also opens additional attack vectors back into PG&E. In addition, the more data being processed and held in cloud environments increases the probability of data exfiltration and the resulting potential impacts.

– **Cyber Identity and Access Management**: The Cyber IAM mitigations, which are part of the Protect mitigation classification, are focused on the identification and authorization of individuals seeking to connect to PG&E networks and systems. This includes the selective granting of access based on a user's role and security classification of a network or system. This mitigation seeks to limit access to systems and therefore reduce the risk of adversaries, or even inadvertent access by PG&E authorized users, which could result in a range of consequences, including loss of life if certain systems were accesses and disrupted.

– **Cyber Privileged Access**: The Privileged Access management mitigations, which are part of the Protect mitigation classification, are critical programs due to the nature of managing privileged access to systems and networks with a high security rating. PG&E tightly controls who has administrative rights and/or access to sensitive systems. If a user requires access, the users must meet the requirements of the Privileged Access management processes and systems. This reduces the risk of an adversary gaining administrative rights which could result in the chances of an adversary being able to change the access list and rights to extremely sensitive networks and systems. The resulting consequences from access to certain systems that could disrupt the business and operational processes could include the loss of life.

– **Cyber ODN Security**: The ODN Security mitigations are focused on the security controls specific to the PG&E OT environment. These security controls are specific to the operational aspects of PG&E operations. These controls are governing and monitoring the cybersecurity mitigation unique to operations technology systems, network, and devices. These assets are critical to the continued delivery of energy products to our customers. PG&E believes the ODN Security mitigations should be pursued due to the wide range of consequences of a cyber-attack on OT systems including the potential for loss of life.

– **App Integration Enterprise Mobility Security SSO**: The proliferation of mobile devices and remote workforce increases the attack surface and cyber-attack vectors. The App Integration Enterprise Mobility Security SSO mitigation provides cybersecurity controls over mobile devices and SSO to PG&E networks and systems. These mitigations assist in the monitoring of cybersecurity controls on mobile devices (advanced mobile device management) and reduces the risk of threat actor access via a mobile device. This in turn reduces the chances that a threat actor could find access to sensitive networks and systems and plant malware that could disrupt critical systems resulting in the potential for loss of life.

– **Security Controls and Infrastructure**: The Security Controls and Infrastructure mitigations reduce the of the potential for loss of life. These mitigations are focused on the cybersecurity tools, deployment, management, and maintenance which provide the core cybersecurity logical/technical controls which help prevent an adverse cybersecurity event. These logical/technical controls are deployed across systems and networks. As such they help protect critical systems which if compromised by a threat actor could result in the potential for loss of life.

- **Security Architecture and Engineering**: The Security Architecture and Engineering mitigations are focused on ‘security by design’ principals and approaches. These mitigations are responsible for developing security architectural ‘patterns’ prior to the build and deployment of IT and OT networks and systems. This approach includes the proactive consideration from emerging threats and reduces the risk of a cyber event that could impact safety of a person or result in loss of life.

E. Alternative Mitigations Analysis

The cybersecurity process for evaluating recommended changes to controls and mitigations is a foundational and organization-wide initiative. This yearly process is designed to evaluate cybersecurity risk (currently identified, and emerging risk), identify gaps or weaknesses, and then evaluate recommendations. Specifically, PG&E cybersecurity reviews the areas of highest risk to PG&E, determines what existing NIST-based controls (administrative and logical/technical) are in place and their effectiveness in the mitigation of risk associated with the cybersecurity Bow Tie. Cybersecurity then performs a qualitative risk assessment for each proposed initiative and determines the level of residual risks if the proposed initiatives are not implemented. This qualitative cybersecurity risk assessment determines the risk associated with a potential cybersecurity attack, including regulatory and privacy violations. The results of the risk assessment are aggregated, including the CBR score related to the proposed initiative, and then the results of the overall BOW risk assessment are aggregated and prioritized to determine which proposed mitigations will provide the greatest risk reduction benefit and value. This is the primary evaluation criteria for the selection of mitigations. Although some analyzed mitigations are deemed to be priority items, budgetary and resource constraints prevent PG&E Cybersecurity from implementing all the recommended mitigations. These mitigations are then considered alternatives and saved for future analysis.

1. Alternative Plan 1: CYBER-A001 – Identify (Alternative)

Shift the emphasis from programs with the NIST CSF classification of ‘Protect’ to programs with a CSF alignment of ‘Identify.’ For information on the differences between these two NIST CSF classifications, see the mitigation summary descriptions in Section C.2. This strategy would shift some of the focus on the current threat landscape to a more proactive focus on the evolving threats. The current mitigation Program ID that is centric to the ‘Protect’ CSF alignment is CYBER-M002 (see Table 2-14) while the current mitigation Program ID aligned to the ‘Identify’ CSF classification is CYBER-M001.c

In considering the CBRs of each mitigation, CYBER-M001 has a CBR of 2.4 while CYBER-M002 has a CBR of 0.8. However, when reviewing the Risk Reduction calculations for each, CYBER-M002 has a greater risk reduction value ($113.1 million) than CYBER-M001 ($56.5 million).

Given the PG&E current state of documented blocked attacks (over a million each month) the decision was to continue to primarily focus on the current threat landscape and mitigation with the CSF classification of Protects and use existing levels of resources in CYBER-M001 to continue to analyze and plan for the evolving threats.

TABLE 2-15
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030

Line No.	Mitigation ID	Mitigation Name	Thousands of Nominal Dollars 2027	2028	2029	2030	Millions of Dollars (NPV)[(a)] Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	CYBER-A001	Identify (Alternative)	$6,521	$6,994	$7,344	$7,711	$30.9	N/A	N/A
2		Total	$6,521	$6,994	$7,344	$7,711	$30.9		

(a) NPV uses a base year of 2023.

For additional details see Exhibit (PG&E-7), WP IT-CYBER-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

2. Alternative Plan 2: CYBER-A002 – Detect (Alternative)

When analyzing the current cybersecurity mitigations focus and deployment, consideration was given to increasing the ability to detect and respond to an adverse cybersecurity event. The strategy would be to increase PG&E's ability to detect an 'indicator of compromise' on the front end, and concurrently increase the ability to respond once a cyber event is detected, however this would require diverting resources from one of the other controls mitigation groups to another. Given the budget constraints a zero-sum game/situation. While both mitigations are highly efficient and mature, the reality of the fluid nature of the current threat landscape coupled with the evolving threats required PG&E to give consideration altering programs emphasis and mitigations.

When analyzing the CBR and Risk Reduction values of the specific mitigations aligned with the CSF category of 'Protect,' CYBER-M002, has a CBR of 0.8 and a Risk Reduction value of $113.1 million. The program and mitigation aligned to the CSF category 'Detect,' CYBER-M003 has a CBR of 1.8 and a Risk Reduction value of $75.1 million. When analyzing the source of the potential resource redeployment, CYBER-M002, CSF aligned to 'Protect' has a higher Risk Reduction value ($113.1 million) than CYBER-M003, CSF aligned to 'Detect ($75.1 million).

Based on this analysis, PG&E decided to maintain the current resource distribution, for the same reason presented in Alternative Plan 1. Given the threat attack numbers, and the nature of the current fluid threat landscape it is was deemed prudent to keep the resources focused on protecting PG&E systems, networks, and data.

TABLE 2-16
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030

			Thousands of Nominal Dollars				Millions of Dollars (NPV)[a]		
Line No.	Mitigation ID	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	CYBER-A002	Detect (Alternative)	$33,073	$37,652	$39,718	$41,564	$164.3	N/A	N/A
2		Total	$33,073	$37,652	$39,718	$41,564	$164.3		

(a) NPV uses a base year of 2023.

For additional details see Exhibit (PG&E-7), WP IT-CYBER-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

PACIFIC GAS AND ELECTRIC COMPANY

RISK ASSESSMENT AND MITIGATION PHASE

CHAPTER 3

RISK ASSESSMENT AND MITIGATION STRATEGY: EMPLOYEE SAFETY INCIDENT

PACIFIC GAS AND ELECTRIC COMPANY
RISK ASSESSMENT AND MITIGATION PHASE
CHAPTER 3
RISK ASSESSMENT AND MITIGATION STRATEGY: EMPLOYEE SAFETY INCIDENT

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PACIFIC GAS AND ELECTRIC COMPANY
RISK ASSESSMENT AND MITIGATION PHASE
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A. Executive Summary

Employee Safety Incident refers to any event resulting in: (1) a serious injury or fatality as defined by Pacific Gas and Electric Company's (PG&E or the Company) Serious Injury and Fatality (SIF) Standard[1] which is aligned with the Edison Electric Institute (EEI) Safety Classification Learning (SCL)[2] model or (2) a Days Away from Work, Restricted Work, or Transferred to Another Job (DART) incident as defined by the Occupational Safety and Health Administration (OSHA). SIF or DART incidents that are the direct result of a PG&E asset failure or equipment malfunction are excluded from the Employee Safety Incident risk. The drivers for this risk are based on SIF (Potential and Actual) investigation cause data aligned with the PG&E Keys to Life,[3] and DART case claim cause categories.

The cross-cutting factors of Records and Information Management (RIM), Physical Attack, Climate Change, and Emergency Planning and Response also impact this risk event.

Exposure to this risk is measured as the approximately 25,000 members of PG&E's workforce. To determine drivers for SIF incidents the model includes sub drivers based on SIF (Potential and Actual) investigation causes for the years 2018 through Q2 2023. The driver responsible for the majority of SIF incidents is Failure to Follow electrical safety testing and grounding rules (Key to Life number 4). Others include: Failure to conduct pre-job safety briefings prior to performing work activities (Key to Life number 1), Failure to follow safe driving principles and equipment operating procedures (Key to Life number 2), Failure

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1 SAFE-1100S – SIF Standard.

2 EEI SCL Model available at: https://www.safetyfunction.com/scl-model (accessed May 1, 2024).

3 The PG&E Keys to Life represent the highest-risk safety commitments that must be followed to prevent serious injury or loss of life.

to follow clearance and energy lockout/tagout rules (Key to Life number 5), Failure to Follow safety at heights rules (Key to Life number 8), and Failure to follow hazardous environment procedures (Key to Life number 10). In addition to the above, Keys to Life drivers responsible for non-SIF DART cases include Failure to follow suspended load rules (Key to Life number 7) and Failure to follow excavation procedures (Key to Life number 9).

The claim cause category sub drivers responsible for the majority of the DART case incidents include Strains (41 percent), Falls, slips, and trips (14 percent), Repetitive Typing/Mousing/Key entry (11 percent), Repetitive Placing/Grasping/Moving Objects/Except Tools (6 percent) and contact with or exposure to harmful substances or environments (6 percent). The mitigations PG&E is implementing from 2023 to 2030 address both field- (SIF and DART) and office-based (DART) risk drivers, including those mentioned above and thus reduce the risk.

PG&E has identified five tranches for this risk event: one for office-based employees; and four for field employees (Electric Operations, Gas Operations, Generation, and Other employees which includes, but is not limited to, Customer & Communications, Utility Operations, Information Technology (IT)/Telecomm, Aviation, Materials Management, and Engineering Planning and Strategy). PG&E defined SIF incidents occur primarily in the field, whereas DART case incidents include both field and office-based work locations. For the datasets used in the model, 100 percent of the risk events resulting in SIFs, and 76 percent of the risk events resulting in DART case incidents are associated with the field employee tranches.

Employee Safety Incident has the seventh-highest 2027 Test Year (TY) Baseline Safety Risk Score ($29.9 million) and the nineteenth-highest 2027 TY Baseline Total Risk Score ($39.1 million) of PG&E's 32 Corporate Risk Register risks.

PG&E is proposing a series of controls and mitigations to address the Employee Safety Incident risk. The PG&E Safety Excellence Management System (PSEMS) and the SIF Capacity and Learning model implementations have the highest cost-benefit ratio (CBR) scores of 5.83 and 5.55 respectively, and the highest total risk reduction scores.

1. Risk Overview

TABLE 3-1
RISK DEFINITION, SCOPE, AND DATA SOURCES

Line No.	Risk Name	Employee Safety Incident
1	Definition	Any event resulting in: (1) a serious injury or fatality as defined by PG&E's SIF Standard which is aligned with the EEI SCL model or (2) a DART incident as defined by the OSHA.
2	In Scope	PG&E employee SIFs including DART cases that are not the result of an asset failure. Public SIFs (California Public Utilities Commission (CPUC or Commission)-reported Public SIF Actuals) resulting from an Employee Safety incident. A SIF Actual (Public) is defined as a fatality or personal injury requiring inpatient hospitalization for other than medical observations that an authority having jurisdiction has determined resulted directly from incorrect operation of equipment, failure or malfunction of utility-owned equipment, or failure to comply with any CPUC rule or standard. Equipment includes utility or contractor vehicles and aircraft used during the course of business. PG&E contractor serious injuries or fatalities resulting from an Employee Safety incident.
3	Out of Scope	PG&E employee SIF and/or DART incidents that are the direct result of a PG&E asset failure or equipment malfunction are excluded from the Employee Safety Incident risk.
4	Data Quantification Sources	PG&E data including: PG&E Human Resources (HR) Report (2018-2022). PG&E California Division of Occupational Safety and Health (Cal-OSHA)-recordable DART case data by claim cause category Incident Detail Report (2018-Q2 2023) PG&E SIF (Potential and Actual) Investigation Reports (2018–Q2 2023)

PG&E has approximately 25,000 employees who provide natural gas and electric services to approximately 16 million people throughout PG&E's 70,000-square-mile service area. PG&E's safety stand is, "Everyone and Everything Is Always Safe." This includes our employee and contract partner workforce, as well as the public. We remain committed to building an organization where every work activity is designed to facilitate safe working conditions and every member of our workforce is encouraged to speak up if they see an unsafe or hazardous condition with the confidence that their concerns and ideas will be heard and addressed. As part of this stand, PG&E is committed to the health and safety of our employees.

The Enterprise Health and Safety (EHS) organization includes health and safety professionals who advise on and lead safety assurance programs, through strategic planning, program governance, safe work practices, EHS analytics and reporting, knowledgeable field health and safety leadership for the prevention of serious injuries and fatalities, projects and program management for workers' compensation case management continuous improvement, life safety and emergency management, regulatory compliance and governance, workforce health, incident investigations and human factor analyses, and enterprise training program governance.

PG&E's team includes a field safety organization led by five Regional Safety Directors who partner with the functional areas (FA) to advise on and facilitate health and safety program implementation and sustainability through the application of best safety practices in each region, and ensure consistency across PG&E.

Safety organization responsibilities for each region include delivering safety programs for safety culture improvements, field observations and hazards identification, and the evaluation of essential control systems for providing co-workers and contract partners with the ability or "capacity" to safely recover from a high-energy incident without life-threatening or life altering injury if an error or mistake is made. Additional efforts include supporting incident investigations, training, safety tailboards, and emergency response.

In addition, key programs that PG&E's EHS organization is responsible for include:

- PG&E Safety Excellence Management System (PSEMS): Previously known as the Health and Safety Management System, PSEMS is the systematic management of our processes, assets, and occupational health and safety programs to prevent injury and illness, effectively and safely control and govern our assets, and manage the integrity of operating systems and processes. PSEMS is grounded in organizational culture and a safety mindset and drives performance in Asset Management, workplace Health and Safety, and Process Safety.

PSEMS is also part of PG&E's Performance Playbook along with Breakthrough Thinking and the Lean Operating Model.

- PG&E's Safety Observations Program: Safety observations reduce injuries and fatalities by increasing awareness of hazards and exposures, and their essential controls. Safety observations reinforce positive work practices and drive a speak-up culture. Safety observation findings provide actionable insights on safety-related strengths, gaps, and trends.
- PG&E's Serious Injury or Fatality (SIF) Prevention Program: All injuries and reported near hits are evaluated to determine the hazards classification and if the situation is a SIF-actual (work-related high-energy incident from work at or for PG&E that results in a fatality, life-threatening, or life-altering injury) or a SIF-potential (high-energy incident where a fatality or life threatening or altering injury is not sustained) event. The Cause Evaluations team conducts in-depth cause evaluations for all incidents classified as SIF-potential or SIF-actual. The results of these investigations and the identified corrective actions are monitored through the Corrective Action Program (CAP) to ensure timely completion and effectiveness including the elimination of recurrence. The SIF Prevention Program is continuously improved through the annual review of existing program processes for enhancement and optimization. This ensures alignment with all FA[4] for enterprise-wide consistency and continuity.
- Enterprise Corrective Action Program (CAP): The Enterprise CAP provides a centralized, standardized governance structure, and process for issue identification and resolution. The CAP process enables employees and contractors the ability to identify and report issues, or ideas, related to gas assets, and processes. The CAP process ensures that issues are categorized, assessed for risk, and assigned to the appropriate owner to resolve issues and implement effective corrective actions to help prevent recurrence. In 2023, PG&E employees and

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4 PG&E changed its title for lines of business (LOB) to FA in 2022.

contractors submitted approximately 27,000 CAP issues Companywide. Examples of how CAP improves safety:

- A PG&E employee observed a pallet jack and a fan stored in an undesignated/unsafe area in the corner of the warehouse which was a possible tripping hazard and submitted a CAP issue. Through CAP, the equipment was moved the very next day eliminating the possible tripping hazard keeping coworkers safe.
- A PG&E employee had been searching for a solution on how to mitigate an unsafe employee moving from one company to another. The Gas Operations Team identified that the unionized contract employees, even if they were removed with or without cause, were returning to site under new employment contracts from the Union Hall, and the new contractor companies were unaware of the safety events that spurred their original dismissals. Three processes were identified that the FA can utilize to promote Contractor Safety and prevent unsafe workers from moving from company to company.
- A motor vehicle incident related CAP issue presented to the incident Review Board led to actions that include HU Tools & SMITH Driver Training.
- A PG&E employee walked over to observe another PG&E crew's excavation job (who was up against a deadline) and saw them digging with a backhoe near an active gas line, which was a safety concern. The crew had a bell hole open where they exposed the pipeline, but it had sloughed back in (sloughing is when the dirt falls back in), and the employee could not see the pipe. The employee stopped the job and kept coworkers and the public safe.
- Just Before the Turnoff to The Kings River Powerhouse, off Trimmer Spring Road there is a flood diversion spillway that looks like a driveway in the dark. An inspector almost turned onto it in the dark. The inspector then spoke with all crews about it (who all almost made the same mistake) which could have resulted in a potential accident or fatality to all who travel that direction. This concern was documented in CAP and resulted in a barrier being placed to prevent any potential accidents or fatalities.

- An employee was reviewing the Motor Vehicle Safety – Driving Expectations and New Laws (TECH-0081WBT) and identified that the spotter was giving hand and arm signals while walking backwards which takes their eyes of the path and makes them vulnerable to a slip, trip, and fall type of injury and submitted a CAP. Through CAP, additional language to the guidance tailboard regarding spotter best practices and guidance was implemented to provide employees a safer means to back vehicles and keep coworkers safe.

- <u>SIF Capacity & Learning Model</u>: The SIF Capacity and Learning model began implementation in 2023, and redefines safety as measured by the presence of essential controls and the ability or "capacity" to experience failures safely. Worksite essential controls directly target the uncontrolled release of high energy (i.e., the "stuff that can kill" or seriously injure a co-worker or contract partner). When essential controls are installed, verified, and used properly, they are not vulnerable to human error. Looking at safety differently with the SIF Capacity and Learning Model advances how we understand, manage, and prevent serious injuries and fatalities. Instead of measuring our success by the number of incidents, we are defining safety by the presence of controls that give coworkers the ability to fail safely.

  Implementation of the SIF Capacity and Learning model includes the use of the ten Human Performance (HU) Tools which include: Questioning Attitude, Tailboards and Pre-Job Brief, Situational Awareness, Self-Checking (STAR), Two-Minute Rule, Three-Way Communication, Stop When Unsure, Procedure Use and Adherence, Phonetic Alphabet, and Placekeeping (i.e., physically marking steps in a procedure or other guiding document that have been completed). The HU Tools are deeply connected to the SIF Prevention Program and in addition to Stop Work Authority allow coworkers to slow things down and reduce the chances of human errors caused by internal and external factors. When used effectively, these tools can also help ensure essential controls effectively remain in place and do not break down.

- Safety Leadership Development: PG&E is continuing to improve Safety Leadership Development and supervisor coaching by continuing to update an impactful, practical training course for front line leaders. The Safety Leadership development program provides training for crew leaders (i.e., those individuals who lead teams of front-line employees doing field operations and maintenance work) so they have the necessary safety skills to create trust, set expectations, remove barriers to safety and identify and mitigate at-risk behaviors.
- Injury Management: Injuries can occur during any work activity (including low or no energy tasks such as lifting, walking, managing tools like knives). The occupational health organization manages employee DART cases (Days Away from work and/or days on Restricted duty or a job Transfer because the employee is no longer able to perform his or her regular job). Since 2019, there has been a 68 percent decrease in the employee DART rate (number of DART cases per 100 full-time employees divided by number of hours worked). The efforts supporting this reduction include the expansion of PG&E's ergonomic programs and increased Industrial Athlete Specialists for job site evaluations. A primary goal of the efforts is reduced injury severity through injury prevention and early intervention care for employees. In alignment with this, we have strengthened the identification of the highest risk work groups and tasks for field and vehicle ergonomic injuries. We identify high-risk computer users through predictive modeling and provide targeted interventions. Additional efforts also include enhanced injury management containment for injuries at risk for escalation to DART and providing our people leaders with additional injury management training.
- Health and Safety Regulatory Compliance Assurance: The EHS organization is responsible for providing health and safety compliance program guidance and advisory oversight, which includes in-depth subject matter expertise on CPUC, Cal/OSHA and OSHA compliance requirements and standards. The health and safety standards align with regulatory compliance requirements and are a resource for the development of work methods and procedures development.

B. Risk Assessment

1. Background and Evolution

The Employee Safety Incident risk was included in PG&E's 2020 Risk Assessment and Mitigation Phase (RAMP).[5] In the 2024 RAMP, the Employee Safety Incident event definition has changed from the 2020 RAMP. The Employee Safety Incident risk event is now defined as any event resulting in: (1) a serious injury or fatality as defined by PG&E's SIF Standard, which is aligned with the EEI SCL model, and/or (2) a DART incident as defined by the OSHA.

The risk drivers in the 2024 RAMP have also evolved. The 2020 RAMP analysis continued to build on risk drivers using Cal/OSHA-recordable injury claim causes and limited direct cause information from the from the discontinued Supervisor Investigation Analysis Packet where available.

The risk drivers for the 2024 RAMP analysis have been updated to include SIF (Potential and Actual) investigation cause data and non-SIF DART case claim cause data.

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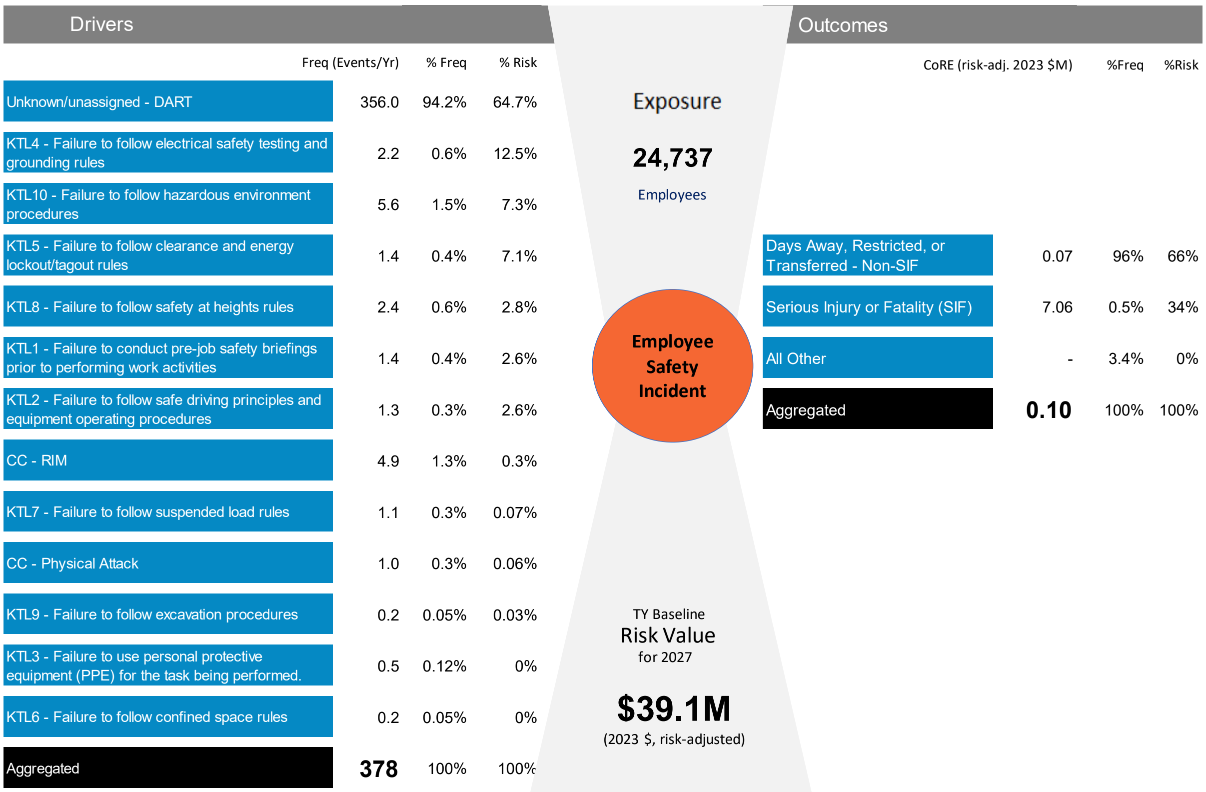
5 PG&E's 2020 RAMP Report, A.20-06-012 (June 30, 2020).

2. Risk Bow Tie

FIGURE 3-1
RISK BOW TIE – 2027 TEST YEAR



3. Exposure to Risk

The Employee Safety Incident risk exposure is based on an annual average of 24,737 employees—approximately 60 percent are considered office-based (i.e., work in PG&E office locations) and approximately 40 percent work primarily in the field.

PG&E relied on its GN 801 – Employee and Non-Employee Details (Internal) Reports for developing the exposure to risk data. PG&E job classifications were used to estimate the number of office and field employees for the exposure tranches.

4. Tranches

PG&E identified five tranches for the Employee Safety Incident risk based on a review of SIF data including OSHA-recordable DART cases:

- PG&E office-based employees, including, but not limited to Managers, Engineers and Scientists, Analysts, Planners, Learning and Development, HR, IT, Supply Chain, Finance, and Law professionals, (60 percent of the workforce); and
- PG&E field employees sub-divided by the core FA, aka LOB (Electric Operations, Gas Operations, Generation) and “Other.” Job types include, but are not limited to: line workers, plant technicians, field analysts, field service representatives, system operators, mechanics, electricians, materials handlers, nuclear security, and troublemen (40 percent of the workforce).

The many of the types of hazards, or risk exposures are different for office- and field-based employees. Office-based employees generally have increased exposure to injuries such as those resulting from typing or key entry, and strains. Field employees have increased exposure to injuries resulting from strains from lifting, pulling, or pushing, repetitive use of tools, contact with objects and equipment, falls from height, and contact with electrical current. Slips, trips, and falls present a hazard and risk exposure to both office-based and field employees. For the datasets used in the model, 100 percent of the risk events resulting in SIFs, and 76 percent of the risk events resulting in DART case incidents are associated with the field employee tranches. Table 3-2 shows the percent risk exposure and percent risk for each tranche.

TABLE 3-2
RISK SCORE AND EXPOSURE BY TRANCHE
(MILLIONS OF DOLLARS)

Line No.	Tranche	Percent Exposure	Safety Risk Score	Financial Risk Score	Aggregated Risk Score	Percent Risk Score
1	Field Employees – Electric Operations	17%	$12.7	$2.8	$15.5	40%
2	Field Employees – Gas Operations	13%	8.3	3.1	11.4	29%
3	Field Employees – Other	6%	4.6	1.0	5.6	14%
4	Field Employees – Generation	2%	0.3	0.2	0.5	1%
5	Office Employees	62%	4.0	2.2	6.2	16%
6	Total	100%	$29.9	$9.3	$39.2	100%

5. Drivers and Associated Frequency

For the 2024 RAMP analysis, drivers were aligned with the PG&E Keys to Life (D1 through D10) and DART cases (D11). Sub Drivers for Drivers D1 through D10 include SIF (Actual and Potential) investigations cause data. Sub Drivers for Driver D11 include DART case claim cause categories. The Drivers and their respective Sub Drivers are below:

- Driver D1: Failure to Conduct pre-job safety briefings prior to performing work activities.
  - Sub Driver 1.1: Inadequate Site Safety Plan/Job Safety Analysis;
  - Sub Driver 1.2: Inadequate Training and/or Job Knowledge; and
  - Sub Driver 1.3: Safe Work Procedures not followed or incomplete.
- Driver D2: Failure to follow safe driving principles and equipment operating procedures.
  - Sub Driver 2.1: Inadequate Communication;
  - Sub Driver 2.2: Inadequate Site Safety Plan/Job Safety Analysis;
  - Sub Driver 2.3: Inadequate Training and/or Job Knowledge;
  - Sub Driver 2.4: Safe Work Procedures not followed or incomplete; and
  - Sub Driver 2.5: Situational Awareness/Lack of work activity focus/clarity.
- Driver D3: Failure to use personal protective equipment for the task being performed.
  - Sub Driver 3.1: Inadequate Personal Protective Equipment (PPE) for the task; and
  - Sub Driver 3.2: Safe Work Procedures not followed or incomplete.
- Driver D4: Failure to Follow electrical safety testing and grounding rules.
  - Sub Driver 4.1: Inadequate Communication;
  - Sub Driver 4.2: Inadequate Site Safety Plan/Job Safety Analysis;
  - Sub Driver 4.3: Inadequate Supervisory Oversight;
  - Sub Driver 4.4: Inadequate Training and/or Job Knowledge;
  - Sub Driver 4.5: Safe Work Procedures not followed or incomplete; and

- Sub Driver 4.6: Situational Awareness/Lack of work activity focus/clarity.

- Driver D5: Failure to Follow clearance and energy lockout/tagout rules.
  - Sub Driver 5.1: Inadequate Site Safety Plan/Job Safety Analysis;
  - Sub Driver 5.2: Inadequate Training and/or Job Knowledge;
  - Sub Driver 5.3: Safe Work Procedures not followed or incomplete; and
  - Sub Driver 5.4: Situational Awareness/Lack of work activity focus/clarity.
- Driver D6: Failure to Follow confined space rules.
  - Sub Driver 6.1: Inadequate Training or Job Knowledge.
- Driver D7: Failure to Follow suspended load rules.
  - Sub Driver 7.1: Inadequate Communication;
  - Sub Driver 7.2: Inadequate Training and/or Job Knowledge;
  - Sub Driver 7.3: Safe Work Procedures not followed or incomplete;
  - Sub Driver 7.4: Situational Awareness/Lack of work activity focus/clarity;
  - Sub Driver 7.5: Inadequate PPE; and
  - Sub Driver 7.6: Inadequate Site safety Plan/Job Safety Analysis.
- Driver D8: Failure to Follow safety at heights rules.
  - Sub Driver 8.1: Inadequate Site Safety Plan/Job Safety Analysis;
  - Sub Driver 8.2: Inadequate Training and/or Job Knowledge;
  - Sub Driver 8.3: Safe Work Procedures not followed or incomplete; and
  - Sub Driver 8.4: Situational Awareness/Lack of work activity focus/clarity.
- Driver D9: Failure to Follow excavation procedures.
  - Sub Driver 9.1: Inadequate Site Safety Plan/Job Safety Analysis.
- Driver D10: Failure to Follow hazardous environment procedures.
  - Sub Driver 10.1: Equipment maintenance;
  - Sub Driver 10.2: Improper Design;
  - Sub Driver 10.3: Inadequate PPE for the task;
  - Sub Driver 10.4: Inadequate Site Safety Plan/Job Safety Analysis;
  - Sub Driver 10.5: Inadequate Training and/or Job Knowledge;

- Sub Driver 10.6: Lack of independent review by PG&E engineering; and
- Sub Driver 10.7: Safe Work Procedures not followed or incomplete.

- Driver D11 – DART cases.
  - Sub Driver 11.1: Assault/attack and other injuries by persons or animal;
  - Sub Driver 11.2: Caught in or by equipment or object;
  - Sub Driver 11.3: Contact with equipment or object;
  - Sub Driver 11.4: Contact with or exposure to harmful substances or environments;
  - Sub Driver 11.5: Falls, slips, and trips;
  - Sub Driver 11.6: Fires and explosions;
  - Sub Driver 11.7: Other;
  - Sub Driver 11.8: Strains;
  - Sub Driver 11.9: Struck by equipment or object;
  - Sub Driver 11.10: Repetitive Use of tools;
  - Sub Driver 11.11: Repetitive Typing/Mousing/Key-entry;
  - Sub Driver 11.12: Repetitive Placing/Grasping/Moving Objects/Except Tools; and
  - Sub Driver 11.13: Transportation non-preventable motor vehicle incidents.

6. Cross-Cutting Factors

A cross-cutting factor is a driver, component of a driver, or a consequence multiplier that impacts multiple risks. PG&E is presenting seven cross-cutting factors in the 2024 RAMP. The cross-cutting factors that impact the Employee Safety Incident risk are shown in Table 3-3 below.

TABLE 3-3
CROSS-CUTTING FACTOR SUMMARY

Line No.	Cross-Cutting Factor	Impacts Likelihood	Impacts Consequence
1	Climate Change	Yes*	No
2	Cyber Attack	No	No
3	Emergency Preparedness and Response (EP&R)	Yes*	No
4	IT Asset Failure	No	No
5	Physical Attack	Yes	No
6	RIM	No	Yes
7	Seismic	No	No

Yes The cross-cutting factor has been quantified in the model.

Yes* The cross-cutting factor does influence the baseline risk but has not been quantified in the model, or the cross-cutting factor may influence the baseline risk but further study is needed.

No The cross-cutting factor does not meaningfully influence the baseline risk.

A description of the cross-cutting factors and the mitigations and controls that PG&E is proposing to mitigate the cross-cutting factors is in Exhibit (PG&E-2), Chapter 3.

The climate change cross-cutting factor was assessed qualitatively with the use of a regional heat index analysis and research article review conducted by PG&E's Climate Resilience team. The analysis indicates an increased number of days where the heat index is above 103 degrees Fahrenheit through 2080. Research on the impacts of increased Heat Index values on cardiovascular deaths related to this show that hotter temperatures will lead to more heat related deaths. Research estimates that each summer, about 71 to 80 days will feel 90 degrees or hotter.[6] Based on these changes, researchers predict the number of annual heat-related cardiovascular deaths will increase 2.6 times for the general population — from 1,651 to 4,320 and that heat-influenced cardiovascular deaths could increase by 233 percent over 13-47 years.[7] Adults aged 65 and older are projected to have a 2.9 to 3.5 times greater increase in cardiovascular death

6 Khatana, Eberly, Nathan and Groeneveld, *Projected Change in the Burden of Excess Cardiovascular Deaths Associated With Extreme Heat by Midcentury (2036-2065) in the Contiguous United States*, (Oct. 2023), Circulation, available at: https://www.ahajournals.org/doi/10.1161/CIRCULATIONAHA.123.066017 (accessed May 1, 2024).

7 *Ibid.*

due to extreme heat, compared with those aged between 20 and 64.[8] PG&E is continuing to monitor Heat illness Protection non-compliance as an EHS FA risk.

Changes in extreme weather conditions and their impacts to employee health and safety risks were not assessed. Additional research may be needed to determine if expected changes in extreme weather due to climate change will impact this risk event.

The EP&R cross cutting factor examines the drivers and consequences of inadequate planning or response to catastrophic emergencies. Inadequate emergency planning or response could have significant safety, reliability, and regulatory impacts. Emergency response and service restoration activities created by the events can increase demands on response and restoration utility workers and increase the risk of work-related fatigue and exposure to workplace hazards if not effectively managed. Long hours can contribute to fatigue and increase the risk for incidents. Research suggests that those who work more than 64 hours per week face 88 percent excess risk.[9]

7. Consequences

The basis for measuring the consequences of the Employee Safety Incident risk for safety are: serious injuries according to the EEI SCL model definition, fatalities, and non-SIF DART cases classified as minor injuries based on Department of Transportation guidance Maximum Abbreviated Injury Scale,[10] and workers compensation average claims costs for financial. There are no electric or gas reliability consequences.

PG&E relied on the PG&E SIF (Actual and Potential) Investigation Reports from 2018 through Q2 2023 and DART case data for this same time frame to analyze the safety consequences of an employee workplace injury. The SIF Investigation Reports provide details on the conditions that led to

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8 *Ibid.*

9 Vegso, S., Cantley, L., Slade, M., et al., *Extended work hours and risk of acute occupational injury: A case crossover study of workers in manufacturing*, (Aug. 2007), American Journal of Industrial Medicine, 50(8), 597-603. doi:10.1002/ ajim.20486.

10 Departmental Guidance, Treatment of the Value of Preventing Fatalities and Injuries in Preparing Economic Analyses, (March 2021).

incidents. DART case data rely on claim causes for insight into incident conditions.

PG&E used the PG&E SEMS database in conjunction with the data derived from the Actuarial Review of Self-Insured Workers' Compensation Program Report, dated January 4, 2023, to evaluate the financial consequences of an employee safety incident. The SEMS database includes the OSHA recordables cases that were classified as DART cases. Historical data were used to quantify the risk baseline with the RAMP model. These same data were used to assess mitigation effectiveness, along with case studies, benchmarking, and PG&E Subject Matter Expert judgment. Greater detail of the mitigation effectiveness methodologies can be found in the workpapers.

Table 3-4 shows the consequences of the risk model. Model attributes are discussed in Exhibit (PG&E-2), Chapter 2.

TABLE 3-4
RISK EVENT CONSEQUENCES

Consequences

	CoRE	%Freq	%Risk	Freq	Natural Units Per Event		Monetized Levels (2023 $M) of a Consequence Per Event		CoRE (risk-adjusted 2023 $M)		Natural Units per Year		Expected Loss per Year (2023 $M)		Attribute Risk Score (risk-adjusted 2023 $M)	
					Safety EF/event	Financial $M/event	Safety $M	Financial $M	Safety	Financial	Safety EF/yr	Financial $M/yr	Safety $M/yr	Financial $M/yr	Safety	Financial
Days Away, Restricted, or Transferred - Non-SIF	0.07	96%	66%	363.2	0.003	0.025	0.046	0.025	0.046	0.025	1.090	9.222	16.596	9.222	16.6	9.2
Serious Injury or Fatality (SIF)	7.06	0%	34%	1.9	0.462	0.018	7.040	0.018	7.040	0.018	0.871	0.034	13.272	0.034	13.272	0.034
All Other	-	3%	0%	12.9	-	-	-	-	-	-	-	-	-	-	-	-
Aggregated	0.1035	100%	100%	378.01	0	0	0.079	0.024	0.079	0.024	1.961	9.256	-	-	29.868	9.256

Note: For additional detail see Exhibit (PG&E-2), Chapter 2.

C. 2023-2026 Control and Mitigation Plan

Tables 3-5 and 3-6 list all the controls and mitigations PG&E included in its 2020 RAMP, 2023 General Rate Case (GRC) and 2024 RAMP (2024-2026 and 2027-2030) for the Employee Safety Incident risk. The tables provide a view of controls and mitigations that are ongoing, those that are no longer in place, and new mitigations. In the following sections, PG&E describes the controls and mitigations in place in the 2023-2026 period, and then discusses new mitigations and/or significant changes to mitigations and/or controls during the 2027-2030 period.

In the 2020 RAMP, the Lack of Fitness for Duty (FFD) Awareness risk (2017 RAMP) was combined with the Employee Safety Incident risk. The scope of the 2024 RAMP for the Employee Safety Incident risk has not changed, other than oversight of the Benefit Plans, Policy, and Wellness compliance programs, which now belongs to the HR organization.

TABLE 3-5
CONTROLS SUMMARY

Line No.	Control Number and Name	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2024-2026)	2024 RAMP (2027-2030)
1	EMPSI-C001 PG&E Health and Safety (OSHA) Compliance	X	Included in EMPSI-PRGA	Included in EMPSI-PRGA	Included in EMPSI-PRGA
2	EMPSI-C001a PG&E Keys to Life control enhancements	NA	NA	Included in EMPSI-PRGA	Included in EMPSI-PRGA
3	EMPSI-C001b Safety Programs: Industrial Hygiene and Hazard Communication	X	Included in EMPSI-PRGA	Included in EMPSI-PRGA	Included in EMPSI-PRGA
4	EMPSI-C001c Safety Programs: Emergency Management, Serious Incident Notification, Heat Illness	X	Included in EMPSI-PRGA	Included in EMPSI-PRGA	Included in EMPSI-PRGA
5	EMPSI-C002 – CAP	X	Included in EMPSI-PRGB	Included in EMPSI-PRGB	Included in EMPSI-PRGB
6	EMPSI-C003 – Employee Knowledge and Skills Assessments (Including Academy Training Requirements Owner [TRO] governance)	X	Included in EMPSI-PRGA	Included in EMPSI-PRGA	Included in EMPSI-PRGA
7	EMPSI-C004 – Safety Observation Program	X	Included in EMPSI-PRGC	Included in EMPSI-PRGC	Included in EMPSI-PRGC
8	EMPSI-C006 – Safety Leadership Development	X	Included in EMPSI-PRGC	Included in EMPSI-PRGC	Included in EMPSI-PRGC
9	EMPSI-C007 and C007a – PG&E's SIF Prevention Program including Near Hits	X	Included in EMPSI-PRGC	Included in EMPSI-PRGC	Included in EMPSI-PRGC
10	EMPSI-C008 – Operational Learning	X	Included in EMPSI-PRGC	Included in EMPSI-PRGC	Included in EMPSI-PRGC
11	EMPSI-C009 – Utility Benchmarking	X (foundational)	Included in EMPSI-PRGA	Included in EMPSI-PRGA	Included in EMPSI-PRGA
12	EMPSI-C010 – Leader in the Field	X	Included in EMPSI-PRGC	Included in EMPSI-PRGC	Included in EMPSI-PRGC
13	EMPSI-C011 – Enterprise Safety Communications	X (foundational)	Included in EMPSI-PRGA	Included in EMPSI-PRGA as foundational	Included in EMPSI-PRGA as foundational
14	EMPSI-C012 – Benefit Plans, and Policy, and Employee Wellness	X	Included in EMPSI-PRGD	Moved to EMPSI-PRGE (managed by HR)	Moved to EMPSI-PRGE (managed by HR)

TABLE 3-5
CONTROLS SUMMARY
(CONTINUED)

Line No.	Control Number and Name	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2024-2026)	2024 RAMP (2027-2030)
15	EMPSI-C013 – FFD Program and Training	X	Included in EMPSI-PRGD	Included in EMPSI-PRGD	Included in EMPSI-PRGD
16	EMPSI-C014 – Enhanced FFD Metrics	X	Included in EMPSI-PRGD	Combined with EMPSI-C013	Combined with EMPSI-C013
17	EMPSI-C015 – Benefit Plans and Policy	X	Included in EMPSI-PRGE	Split into EMPSI-C015a (EMPSI-PRGE) and EMPSI-C015b (EMPSI-PRGD)	Split into EMPSI-C015a (EMPSI-PRGE) and EMPSI-C015b (EMPSI-PRGD)
18	EMPSI-C015a – Benefit Plans and Policy – Leaves including Long and Short terms disability		Included in EMPSI-PRGE	Included in EMPSI-PRGE (managed by HR)	Included in EMPSI-PRGE (managed by HR)
19	EMPSI-C015b – Workers Compensation (WC) Program		Included in EMPSI-PRGE	Included in EMPSI-PRGD	Included in EMPSI-PRGD
20	EMPSI-C016 – Nurse Care Line (NCL)	X	Included in EMPSI-PRGE	Moved to EMPSI-PRGD	Included in EMPSI-PRGD
21	EMPSI-C017 – Return to Work Task Program	X	Included in EMPSI-PRGE	Included in EMPSI-PRGE (managed by HR)	Included in EMPSI-PRGE (managed by HR)
22	EMPSI-C018 – EHS data management, governance, and regulatory reporting		Included in EMPSI-PRGA	Included in EMPSI-PRGA	Included in EMPSI-PRGA
23	EMPSI-C019 – Musculoskeletal Disorder (MSD) Prevention – Ergonomics and Industrial Athlete Programs		Included in EMPSI-PRGD	Included in EMPSI-PRGD	Included in EMPSI-PRGD
24	EMPSI-C020 – On-site Clinics	Was EMPSI-M011	Was EMPSI-M011	Included in EMPSI-PRGD	Included in EMPSI-PRGD
25	EMPSI-C021 – Safety Recognition Program (foundational)	NA	NA	Included in EMPSI-PRGC	Included in EMPSI-PRGC
26	EMPSI-C022 – Safety Culture Assessment and Monitoring	NA	NA	EMPSI-PRGF	EMPSI-PRGF
27	EMPSI-C023 - Health and Wellness data warehouse (foundational)	X	X	Included in EMPSI PRGD	Included in EMPSI PRGD

TABLE 3-6
MITIGATIONS SUMMARY

Line No.	Mitigation Number and Name	2020 RAMP (2020-2022)	2023 GRC (2023-2026)	2024 RAMP (2023-2026)	2024 RAMP (2027-2030)
1	EMPSI-M01B – ESMS Implementation	X	Becomes EMPSI-M01B	X	Becomes control EMPSI-C25 and with be part of Safety Assurance and PSEMS governance (EMPSI-PRGF)
2	EMPSI-M06a – Office Ergonomics Program	X	Becomes EMPSI-M06a	Becomes EMPSI-C019	Becomes EMPSI-C019
3	EMPSI-M06b – Industrial Ergonomics Program	X	Becomes EMPSI-M06b	Becomes EMPSI-C019	Becomes EMPSI-C019
4	EMPSI-M06c – Industrial Athlete Program	X	Becomes EMPSI-M06c	Becomes EMPSI-C019	Becomes EMPSI-C019
5	EMPSI-M06d – Vehicle Ergonomics Program	X	Becomes EMPSI-M06d	Becomes EMPSI-C019	Becomes EMPSI-C019
6	EMPSI-M011 – On-Site Clinics	X	Becomes EMPSI-M011	Becomes EMPSI-C020	Becomes EMPSI-C020
7	EMPSI-M013 – Enhancing SafetyNet Use	X	Becomes EMPSI-M013	Becomes EMPSI-C004	Becomes EMPSI-C004
8	EMPSI-M014 – Industrial Hygiene (IH) Program Compliance Improvements	X	Becomes EMPSI-M014	Becomes EMPSI-C001b	Becomes EMPSI-C001b
9	EMPSI-M016 – Fit4U Pilot	X	Becomes EMPSI-M016	X	Transitions to EMPSI-C024 in 2028
10	EMPSI-M017 – Mobile Medics	X	Project Discontinued		
12	Ergonomics Program – Industrial Ergonomics Predictive Model (foundational)				X
13	EMPSI-M019 – Ergonomics Program – Functional Movement Screening				X
14	EMPSI-M020 – PG&E’s SIF Prevention Program Capacity & Learning Model			X	Becomes control EMPSI-C026 in 2029

1. Controls

The controls and mitigations proposed in the 2024 RAMP for the Employee Safety Incident risk are programs designed to provide Companywide infrastructure to support the continued strengthening of PG&E's compliance and safety culture. The list of controls below reflects the 2023 baseline for the Employee Safety Incident risk. The control programs and their associated individual controls or measures are anticipated to remain in place through 2030.

EMPSI-C001 – PG&E Health and Safety Compliance: Health and Safety (H&S) Compliance programs management and advisory oversight including in-depth subject matter expertise on Cal/OSHA and OSHA compliance requirements and standards. H&S standards are used as the basis for FA work methods and procedures development. This control is part of the Health and Safety Regulatory and Compliance Assurance Guidance, Training and Oversight Program (EMPSI-PRGA).

EMPSI-C001a – PG&E Keys to Life Control Enhancements: Clarify Keys to Life standards, simplifying work methods, define essential controls, evaluate training, refresher and validation program starting with top five Keys to Life (Pre-job safety briefing, electrical safety testing and grounding, hazardous environment/line of fire, PPE, safe driving). Additional Keys to Life were assessed as part of a Failure Modes and Effects Analysis with recommended enhancement actions for failure modes determined as high-risk. This control is part of the Health and Safety Regulatory and Compliance Assurance Guidance, Training and Oversight Program (EMPSI-PRGA).

EMPSI-C001b – Safety Programs: Industrial Hygiene and Hazard Communication: IH and Hazard Communications Safety programs management and advisory oversight including in-depth subject matter expertise on Cal/OSHA and OSHA compliance requirements and standards. This control is part of the Health and Safety Regulatory and Compliance Assurance Guidance, Training and Oversight Program (EMPSI-PRGA).

EMPSI-C001c – Safety Programs: Emergency Management, Serious Incident Notification, Heat Illness: Emergency Management, Serious Incident Notification, Heat Illness Safety programs management and advisory oversight including in-depth subject matter expertise on Cal/OSHA and OSHA compliance requirements and standards. This control is part of the Health and Safety Regulatory and Compliance Assurance Guidance, Training and Oversight Program (EMPSI-PRGA).

EMPSI-C002 – Corrective Action Program: The CAP is a Companywide program that provides employees and contractors a speak-up method to identify and report issues, or ideas, related to gas assets, and processes. The CAP process ensures that issues are categorized, assessed for risk, and assigned to the appropriate owner to resolve issues and implement effective corrective actions to help prevent recurrence. Both employees and contractors have the option of submitting a CAP anonymously. This control is the CA Program (EMPSI-PRGB).

EMPSI-C003 – Employee Knowledge and Skills Assessments: In conjunction with the PG&E Learning Academy, PG&E's FAs are developing specific Employee Safety knowledge and skills assessments. The training provides classroom and hands-on instruction by experienced instructors to teach and assess the specialized skills that are critical to field employees executing high risk tasks. EHS advises on programs as training requirements owners (TRO). This control is part of the Health and Safety Regulatory and Compliance Assurance Guidance, Training and Oversight Program (EMPSI-PRGA).

EMPSI-C004 – PG&E Field Safety Observations Program and High Energy Controls Assessments (HECA): Functional Area (aka LOB) supervisory and corporate Health and Safety Specialists conduct worksite observations using checklists developed using SafetyNet (PG&E's Safety Observation database tool) as part of the SIF Program implementation. The benefits of SafetyNet are that it leverages a large and comprehensive database of 500 million data points from completed observations throughout the industry and includes algorithms to provide predictive injury analysis, dashboards, and help with improving the quality of the submitted observations.

As part of the GRC proposed plan (EMPSI-M13), PG&E enhanced its use of the SafetyNet safety observation tool, developed by Predictive Solutions, for use with field employees and contractor safety programs. The benefits of SafetyNet are that it leverages a large and comprehensive database of several million completed observations and includes algorithms that have the potential to provide predictive analysis and dashboards regarding unsafe conditions or behaviors enterprise-wide. This mitigation was fully optimized in 2021 and transitioned to a control in 2022.

In 2023, PG&E initiated the pilot phase of HECA and has integrated the assessments into the Safety Observations Program as of January 1, 2024. HECA is a new method of measuring and monitoring safety by assessing whether front-line employees are adequately protected against life-threatening hazards. HECA is computed as the percentage of high-energy hazards that have corresponding direct controls. This control is part of the SIF Prevention Program and Field Oversight Program (EMPSI-PRGC).

EMPSI-C006 – Safety Leadership Development: All PG&E employees in Frontline leadership positions who have union represented employees within their reporting structure/chain of command who work in a capacity that has a SIF potential are identified to take the revised SLD workshop series. The workshops teach and focus on leadership skills and practices that promote and sustain safety performance. The PG&E People Development team is responsible delivering, maintaining, and updating the workshops. Workshops are updated annually to address areas of improvement identified by the field safety observation data. This control is part of the SIF Prevention Program and Field Oversight Program (EMPSI-PRGC).

EMPSI-C007 and EMPSI-C007a – PG&E's Serious Injury or Fatality Prevention Program: The SIF Prevention Program focuses on SIFs at PG&E. All injuries and reported near hits are evaluated to determine the hazards classification and if the situation results in a SIF-actual or SIF-potential event. The Cause Evaluations team conducts in-depth cause evaluations for all incidents classified as SIF potential or SIF actual. The results of these investigations and the identified corrective actions are monitored through the CAP to ensure timely completion and effectiveness. Focusing its investigative resources on SIF-potential and SIF-actual incidents assists with understanding these situations and the development of corrective actions to eliminate or mitigate recurrence. The SIF Program is continuously improved through the review of existing SIF Program and processes for enhancements and optimization on an annual basis, ensuring alignment with all LOBs for consistency and continuity enterprise-wide. This control is part of the SIF Prevention Program and Field Oversight Program (EMPSI-PRGC).

EMPSI-C008 – Operational Learning: PG&E's Operational Learning uses several different methods that are focused on learning about how work is performed. Learning Teams, a critical component of Operational Learning, are facilitated discussions with representative groups of front-line employees, led by a trained facilitator, about how work is performed, what works well, and what are the barriers to success. Learning Teams leverage employees' extensive expertise and experience to identify best practices and to develop practical and sustainable solutions to improve operating and safety performance. This effort helps PG&E FAs understand how work is done and to develop approaches and solutions to reduce risk and improve workplace safety. Recommended improvements are entered and evaluated through the CAP. This control is being refreshed as part of the SIF Capacity & Learning model field implementation this year (2024). This control is part of the SIF Prevention Program and Field Oversight Program (EMPSI-PRGC).

EMPSI-C009 – Benchmarking: Utility industry benchmarking (e.g., Cal/OSHA, EEI metrics). This control is foundational and was combined with EMPSI-C18 (EHS Data Management, Governance, and Regulatory Compliance Reporting).

EMPSI-C010 – PG&E's Leader in the Field: The Leader in the Field initiative focuses on having leaders spend more time in the field and coaches them on how to provide consistent feedback to workers, engage with them in discussions with how they are working safely, and how to offer specific guidance on how to improve. This control is part of the SIF Prevention Program and Field Oversight program (EMPSI-PRGC).

EMPSI-C011 – Enterprise Safety Communications (foundational): The enterprise safety communications are part of Corporate Communications, with the objective of delivering a consistent Health and

Safety communication strategy, which helps employees understand the risk factors for their health and safety. This allows employees to understand, engage with, and appreciate the health and safety programs available to them and build credibility with employees and contractors by showing that PG&E is a company committed to worker safety. This program is foundational in that it enables the effectiveness of many of the other EHS controls and mitigation programs. Cost thresholds are below the formal foundational activities criteria. This control is part of the Health and Safety Regulatory and Compliance Assurance Guidance, Training and Oversight Program (EMPSI-PRGA).

EMPSI-C012 – Benefit Plans, and Policy, and Wellness (HR): These programs align health and wellness activities with safety prevention efforts to drive better outcomes. Research has shown a direct correlation between the health and well-being of employees and their frequency of being injured on the job. Expanded and enhanced health and wellness services/controls promote access to medical services and other programs and focus on prevention to assist employees in managing their health. On-site health coaching has been added and a new employee health and wellness portal was implemented with tools and additional self-directed resources. There are two main categories of Health and Wellness controls:

a) Emotional Health – Employee Assistance Program (EAP) and Peer Volunteer Program. The EAP services include counseling, legal and financial consultations, support after a critical incident, and substance use disorder support for coworkers subject to DOT or NRC guidelines. By addressing personal issues that could cause workplace distractions, risk for an injury is reduced.

b) Physical Health – Employee Health Screenings and Health Coaching. Health Screenings provided to help employees determine if they are at risk for developing serious health conditions such as heart disease or diabetes. Employees at risk for serious conditions are also at increased risk for major health events or safety incidents. Health Coaching is provided to help employees achieve health goals, decrease health risks, and promote healthy habits.

Other benefits of these programs may include improved productivity and engagement, reduced absenteeism and presenteeism, coworker retention, and reduced healthcare costs. This control is part of the Benefit Plans, Policy, and Wellness Program now overseen by HR (EMPSI-PRGE).

EMPSI-C013 –Fitness for Duty (FFD) Program and Training: The FFD Program is intended to ensure a safe workplace for coworkers, customers, and the communities in which we serve. A FFD evaluation helps determine, based on direct workplace observations, if there is a physical, psychological, or cognitive condition which may be impairing a coworker's ability to perform the essential functions of their job with or without reasonable accommodations. Training and communication enhance people leader awareness and effectiveness in detecting behaviors that raise FFD concerns. There are three types of training: (1) New to Leadership training which helps new leaders understand how to identify and react to observed behaviors which may impact the employees' ability to perform their work safely, (2) FFD Cross Program Manager Training (resources and process to ensure adequate coverage), and (3) Voluntary FFD situational awareness training for leaders. The FFD Program Manager regularly provides ad hoc FFD training to leaders upon request, allowing leaders to ask questions and interact directly with the FFD Program Manager. Enhanced FFD data tracking metrics includes risk ranking, late or timely reporting. Mandatory FFD training for people leaders, Directors and below, is tracked through Learning Academy (previously EMPSI-C14). This control is part of the Employee Occupational Health and Wellness program (EMPSI-PRGD).

EMPSI-C014 – Enhanced FFD Metrics: Combined with EMPSI-C13 above.

EMPSI-C015a – Benefit Plans and Policy (HR) – Leaves Including Long- and Short-Term disability: Implemented a third party to administer multiple benefit program offerings, including long-term disability, short-term disability, paid family leave, the PG&E's Voluntary Disability and Paid Family Leave Benefit Plan (offered in lieu of State Plan benefits) and leaves of absence to improve employee access to benefit information. Having a single administrator helps to ensure proper administration of benefits which ensures compliance with complex leave laws and other regulatory requirements. New benefits provide eligible employees with a financial safety net to be able to take the time off needed to seek treatment and help in recovery, thus improving and/or maintaining the health of the workforce and assuring quality of care and fitness to return-to-work. This control is part of the Benefit Plans, Policy, and Wellness Program now overseen by HR (EMPSI-PRGE).

EMPSI-C015b – Workers Compensation (WC) Program: PG&E is self-insured and self-administered for WC in California. Under this program, PG&E provides WC benefits required by California law and by contract. PG&E provides the following to injured workers under its self-insured WC Program; medical treatment necessary to cure or relieve the effects of the injury, disability payments made directly to the injured worker if the injury results in temporary or permanent disability, vocational rehabilitation vouchers, death benefits, and supplemental benefits. In addition to benefits, this control includes cost containment programs such as Utilization Review (UR), Bill Review, and Nurse Case Management. PG&E utilizes a UR company certified to ensure medical treatment requests are compliant with the Division of Workers' Compensations Medical Treatment Utilization Schedule. PG&E utilizes a Bill Review company to ensure medical payments are consistent with the California's Official Medical Fee Schedule, and captures discounts below fee schedule, available through Preferred Provider Organization (PPO) Networks. PG&E utilizes Nurse Case Managers to assure medical care is progressing effectively. This control is part of the Employee Occupational Health and Wellness Program (EMPSI-PRGD).

EMPSI-C016 – Nurse Care Line (NCL): PG&E uses a NCL as its primary injury reporting claim intake method. The NCL provides 24-7 support and access to trained medical professionals for PG&E coworkers experiencing work-related discomfort or injury. Enhanced injury reporting improves the coworker experience when reporting minor injuries. Early intervention is the key to successfully managing physical discomfort or stress. The NCL allows coworkers to speak up, without fear, when faced with a work-related health challenge, strengthening the message that coworker health is essential. Coworkers receive medical advice, self-care information, and clinic referrals. Using the NCL results in a decrease of injury severity, and a reduction in workers compensation claim costs. While the number of calls to the NCL has increased, the percentage of those calls resulting in OSHA recordables has decreased by 16 percent from 2014 through June 2023. It also identifies training opportunities to further promote a safe working environment. Enhancements were made in 2022 that streamlined the process include the implementation of a new app and a closed-caption option for the hearing impaired. This control is part of the Employee Occupational Health and Wellness Program (EMPSI-PRGD).

EMPSI-C017 – Return to Work Task Program (HR): The enhanced return to work task program provides more return-to-work opportunities for employees with injuries or illnesses (industrial and non-industrial) whose temporary work restrictions cannot be accommodated in their base classification. This control provides temporary assignments to help ease the transition from temporary restricted status to full duty. Early return to work helps injured employees recover faster and have better recovery outcomes. The program has resulted in a significant reduction of lost workdays. This control is part of the Benefit Plans, Policy, and Wellness Program now overseen by HR (EMPSI-PRGE).

EMPSI-C018 – EHS Data Management, Governance, and Regulatory Compliance Reporting: Management and oversight of PG&E EHS compliance and reporting requirements including Cal/OSHA injury and illness recordkeeping and reporting, utility benchmarking, and CPUC regulatory filings. This control assures compliance through enterprise-wide internal communications, and external communications regarding compliance status and metrics. This control is part of the Health and Safety Regulatory and Compliance Assurance Guidance, Training and Oversight Program (EMPSI-PRGA).

EMPSI-C019 – Musculoskeletal Disorder (MSD) Prevention – Ergonomics and Industrial Athlete Programs: The Ergonomics and Industrial Athletes programs provide proactive and reactive musculoskeletal injury interventions for office- and field-based employees to ensure compliance with Cal/OSHA Title 8, Section 5110 – Repetitive Motion

Injuries. Interventions include annual training on MSD injury prevention and ergonomics; individual one-on-one ergonomics assessments that include identification of ergonomics risk factors and controls to reduce ergonomics risk, such as alternate tools, workstation adjustments, work technique recommendations, biomechanical coaching and the like; work task ergonomics assessments; and prevention through design strategies, including furniture, work area and vehicle design considerations to accommodate the workforce using 5th-95th percentile anthropometric data and human factors principles.

Between 2020 and 2022, planned mitigations through 2026 were operationalized into the overall Ergonomics and Industrial Athlete program. These include:

Office Ergonomics Program (formerly EMPSI-M006a): Continued effort on change management, including Supervisor training within the organization for early symptom recognition and action, working with facilities partners to ensure furnishings meet ergonomic design specifications, and enhanced reporting through predictive modeling. This mitigation transitioned to a control in 2022.

Industrial Ergonomics (IE) Program (formerly EMPSI-M006b): Continued effort in education about IE risk factors, while making the IE software fully operational across enterprise with prevention specialists and IE teams. The IE software is used to assess ergonomics risk factors associated with worker activities and tasks and determine possible risk reduction measures. This mitigation also included building a business case for a centralized pilot to evaluate potential solutions, increase partnerships with the vendor to receive products to pilot across enterprise needs, robust tracking, reporting, and visibility of impacts and risk reduction from solution implementation. This mitigation transitioned to a control in 2022.

Industrial Athlete Program (formerly EMPSI-M006c): Expansion from early symptom intervention to a strategic-based plan to reduce discomfort cases and prevent muscle strains and sprains. Program objectives include targeted interactions with an on-site prevention specialist by focusing on high-risk areas identified by Supervisors, brief surveys, and biomechanical observations. The Industrial Athlete program is managed internally and utilizes an external third party for on-site services. This mitigation transitioned to a control in 2022.

Vehicle Ergonomics Program (formerly EMPSI-M006d): All PG&E-owned vehicles included in PG&E's fleet have a design review committee that includes front-line workers, safety, ergonomics, and human factors. The objective is to fully understand the work performed while using the vehicles, such as equipment most frequently used, access, lighting, environmental concerns, smart driving, ease of access, mechanical advantage, and forecast potential future technology impacts, using 5-95 percent anthropometric data and human factors principles. This mitigation transitioned to a control in 2022.

Planned control enhancements for 2023-2026 include replacing existing ergonomics software with alternate vendors that will include risk management of office and Industrial Ergonomics (IE) (e.g., using wearables). The new Ergonomics software solution is being implemented in 2024. The software program is foundational in that it enables the continued improvements to the Ergonomics and Industrial Athlete Programs controls and mitigation programs. Cost thresholds are below the formal foundational activities criteria. This control is part of the Employee Occupational Health and Wellness Program (EMPSI-PRGD).

EMPSI-C020 – On-site Clinics (formerly EMPSI-M011): The on-site and near-site clinics provide coworkers with convenient access to health care services leading to a healthier workforce by reducing the duration of Days Away From Work and Restricted Duty cases. Three on-site/near-site locations in Fresno, San Carlos, and Oakland (near-site) became operational in 2022, offering both non-occupational and occupational care. Additional expansion to new locations at this time is not deemed cost effective. This was in part a result of the shift to a more remote workforce, planned closure of certain office spaces, and the increased availability of virtual care that can now be offered through the three existing sites. In addition, the onsite clinic at the Diablo Canyon Power Plant offers occupational care, medical surveillance, fitness testing, and limited non-occupational assessments. This control is part of the Employee Occupational Health and Wellness Program (EMPSI-PRGD).

EMPSI-C021 - Safety Recognition Program (foundational): Enterprise Safety Recognition Program. Achieving our Safety Stand and building a safety-first culture requires ownership from every PG&E coworker and contract partner. There are examples of this in every corner of the Company and the program is focused on recognizing these coworkers, including a focus on proactive safety behaviors, such as near-hit reporting, field safety observations, speaking up, stopping work, sharing lessons learned and coaching. This program is foundational in that it enables many of the other EHS controls and mitigation programs. Cost thresholds are below the formal foundational activities criteria. This control is part of the SIF Prevention Program and Field Oversight Program (EMPSI-PRGC).

EMPSI-C022 – Safety Culture Assessment and Monitoring: New beginning in 2024, continued monitoring and assessment of the effectiveness of the PSEMS and the Workforce Safety Strategy implementations with recommendations for course correction and improved effectiveness. This control is part of the Safety Assurance Program (EMPSI-PRGF).

EMPSI-C023 – Health and Wellness data warehouse (foundational): The Health and Wellness data warehouse supports up-to-date strategic analytics, on-line dashboards and query, and information-driven policy and benefit design. This control is part of the Employee Occupational Health and Wellness Program (EMPSI PRGD).

2. Mitigations

The list of the mitigations represents the mitigations implemented in the 2023-2026 period that will affect the 2027 Test Year Baseline Risk Value. Mitigation costs are summarized in Table 3.7 below.

EMPSI-M001B – PG&E Safety Excellence Management System (PSEMS) Formerly Known as Enterprise Safety Management System Implementation: PSEMS consists of a series of capabilities (people, process, governance, and technology systems) required to define, plan, implement, and continuously improve workforce safety. PSEMS becomes the way PG&E "delivers the business of safety" and is based on a consistent and comprehensive enterprise safety controls framework reinforced with system assurance. PG&E's commitment is to operationalize the system through 2025. This program will transition to control EMPSI-C025, part of program EMPSI-PRGF Safety Assurance and PSEMS governance in 2027.

EMPSI-M016 – Fit4U Program: This program focuses on improving the health and well-being of employees who have sustained multiple workers' compensation injuries by providing them with the resources to maintain a healthy lifestyle. Access to nutritional guidance, personal training, health coaching, meditation/mindfulness, and EAP services should prevent repeat injuries, provide coping skills, and accelerate their recovery and return to work. Long term benefits may include a reduction in workers' compensation claims, health plan costs, work-related injuries or illnesses, DART rate, and health related lost workdays. Analysis of the results from the Fit4U pilot and the interim virtual program offered during COVID determined program expansion is worthwhile and planning for an enterprise-wide implementation in 2024 began in 2023 as discussed in the Changes to Mitigations section below. This program will transition to control Employee Occupational Health and Wellness Program (EMPSI-PRGD) in 2028 as control EMPSI-C024.

EMPSI-M017 – Mobile Medics: PG&E Emergency Medical Technicians (EMT) throughout seven territories with the highest OSHA-recordable injuries over the last three years. This mitigation was discontinued due to low utilization.[11]

EMPSI-M020 – SIF Capacity & Learning Model: New for 2024, the SIF Capacity and Learning model redefines safety as measured by the presence of essential controls and the capacity to experience failures safely. Worksite essential controls directly target the stuff that can kill or seriously injure a co-worker or contract partner. When the controls are installed, verified, and used properly, they are not vulnerable to human error. Looking at safety differently with the SIF Capacity and Learning Model advances how PG&E will understand, manage, and prevent serious injuries and fatalities (SIFs). Instead of measuring success by the number of incidents, safety is defined by the presence of controls that give coworkers the ability to "fail safely."

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11 A.21-06-021, 2023 GRC Exhibit (PG&E-7), Chapter 1, p. 1-35.

Implementation of the SIF Capacity and Learning model includes the use of 10 Human Performance (HU) Tools which include: Questioning Attitude, Tailboards and Pre-Job Brief, Situational Awareness, STAR, 2-Minute Rule, 3-Way Communication, Stop When Unsure, Procedure Use and Adherence, Phonetic Alphabet, and Placekeeping (i.e., physically marking steps in a procedure or other guiding document that have been completed). The HU Tools are deeply connected to the SIF Prevention Program and in addition to Stop Work Authority allow coworkers to slow things down and reduce the chances of human errors caused by internal and external factors. When used effectively, these tools can also help ensure essential controls effectively remain in place and do not break down. This program will transition to control program EMPSI-PRGC SIF Prevention Program and Field Oversight in 2029 as control EMPSI-C26.

Table 3-7 below shows the cost estimates for the mitigations planned for the 2024-2026 timeframe.

TABLE 3-7
MITIGATIONS COST ESTIMATES
2024-2026 EXPENSE
(THOUSANDS OF NOMINAL DOLLARS)

Line No.	Mitigation ID[(a)]	Mitigation Name	2024	2025	2026	Total
1	EMPSI-M001B	PSEMS (aka ESMS) Implementation	$1,470	$460	$1,115	$3,045
2	EMPSI-M016	Fit4U Program	310	280	464	1,054
3	CNTSI-M020, EMPSI-M020	SIF Capacity and Learning Model	85	80	80	245
4	Total		$1,865	$820	$1,659	$4,344

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

For additional details see workpaper (WP) EHS-EMPSI-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

3. Foundational Activities

As discussed in Exhibit (PG&E-2), Chapter 2, foundational activities are programs that enable two or more control or mitigation programs but do not directly reduce the consequences or the likelihood of risk events. The

Commission requires Investor-Owned Utilities to include forecast costs of foundational activities in the CBR calculations for the control and mitigation programs that the foundational activities enable, subject to minimum cost thresholds.[12] This section lists foundational activities that support two or more planned mitigations or controls over the 2027-2030 period. However, costs for the foundational activities are below the minimum threshold for inclusion in CBR calculations.

- **Ergonomics software implementation through 2024:** Supports the Ergonomics programs and their effectiveness and ability to implement planned mitigations (control EMPSI-C019);
- **Ergonomics Industrial Ergo Predictive Model implementation 2027 through 2030:** Supports the Ergonomics programs and their effectiveness (control EMPSI-C019) which is part of the Employee Occupational Health and Wellness Program (EMPSI-PRGD);
- **EMPSI-C011 – Enterprise Safety Communications**;
- **EMPSI-M014 – Industrial Hygiene Program Compliance Improvements:** Previously EMPSI-M014 – Industrial Hygiene Program Compliance Improvements – Phase 1. New in 2024 as a foundational activity, completion of this mitigation includes the consolidation of monitoring records and compliance recordkeeping, exposure assessments, and medical surveillance program in a cost effective IH data management software system through 2024. This program is foundational as it supports the IH Program and will transition to control program Health and Safety Regulatory and Compliance Assurance Guidance, Training and Oversight Program (EMPSI-PRGA) this year.
- **EMPSI-C021** – **Safety Recognition Program**.

D. 2027-2030 Proposed Control and Mitigation Plan

1. Changes to Controls

There are six control programs described above that continue through the years 2027 through 2030. Each of the programs includes a series individual controls or measures as mentioned in the Controls section above and as shown

[12] See Exhibit (PG&E-2), Chapter 2, Section D.4.g.

in Table 3-8 below. Table 3-9 below shows the cost estimates, risk reduction values, and CBRs for the control programs.

TABLE 3-8
2027-2030 CONTROL PROGRAMS

Line No.	Control ID	Control Program	Individual Measures
1	EMPSI-PRGA	Health and Safety Regulatory and Compliance Assurance Guidance, Training and Oversight	EMPSI-C001 PG&E Safety and Health (OSHA) Compliance EMPSI-C001a Control enhancements - Keys to Life EMPSI-C001b Safety Programs: Industrial Hygiene and Hazard Communication EMPSI-C001c Safety Programs: Emergency Management, Serious Incident Notification, Heat Illness EMPSI-C003 Employee Knowledge and Skills Assessments EMPSI-C011 Enterprise safety communications EMPSI-C018 EHS data management, governance, and regulatory reporting
2	EMPSI-PRGB	Corrective Action Program	The CAP is a companywide program that provides employees and contractors a speak-up method to identify and report issues, or ideas, related to gas assets, and processes. The CAP process ensures that issues are categorized, assessed for risk, and assigned to the appropriate owner to resolve issues and implement effective corrective actions to help prevent recurrence.
3	EMPSI-PRGC	SIF Prevention Program and Field Oversight	EMPSI-C004 Safety Observation Program EMPSI-C006 Safety Leadership Development EMPSI-C007 and C007a PG&E's Serious Injury and Fatality (SIF) Prevention Program EMPSI-C007b PG&E's Serious Injury and Fatality (SIF) Prevention Program Capacity & Learning Model EMPSI-C008 Operational Learning EMPSI-C010 PG&E's Leader in the Field EMPSI-C021 Safety Recognition Program EMPSI-C026 - SIF Capacity and Learning Model (begins in 2029)
4	EMPSI-PRGD	Employee Occupational Health and Wellness	EMPSI-C013 Fitness For Duty (FFD) Program and Training EMPSI-C015b Workers Compensation (WC) Program EMPSI-C016 Nurse Care Line (NCL) EMPSI-C019 MSD Prevention – Ergonomics and Industrial Athlete Programs EMPSI-C020 On-site Clinics EMPSI-C023 Health and Wellness data warehouse (foundational; previously included with EMPSI-PRGA) EMPSI- C024 Fit4You Program (transitions in 2028)
5	EMPSI-PRGE	Benefit Plans, Policy, and Wellness Programs (HR)	EMPSI-C015a Benefit Plans and Policy, and Leaves including Long- and Short-term disability EMPSI-C012 Benefit Plans, and Policy, and Wellness including EAP EMPSI-C017 Return to Work Task Program
6	EMPSI-PRGF	Safety Assurance and PSEMS governance	To include PSEMS and related programs governance as they are operationalized. Including Near Hit Program, current Safety Assurance Program, Safety Culture Assessment and Self-Evaluations, and the Safety Culture Monitoring Program as control EMPSI-C022. PSEMS becomes control EMPSI-C025 in 2028.

TABLE 3-9
CONTROLS COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030

			Thousands of Nominal Dollars				Millions of Dollars (NPV) [(a)]			
Line No.	Control ID	Control Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[(b)] [C]/([A]+[B])
1	EMPSI-PRGA	Health and Safety Regulatory and Compliance Assurance Guidance, Training and Oversight	$5,844	$5,980	$6,119	$6,263	$16.7	–	$48.8	2.9
2	EMPSI-PRGB	CAP	3,536	3,625	3,715	3,808	10.1	–	52.5	5.2
3	EMPSI-PRGC	SIF Prevention Program and Field Oversight	13,314	13,647	13,988	14,337	38.1	–	52.5	1.4
4	EMPSI-PRGD	Employee Occupational Health and Wellness	76,921	78,370	79,102	81,064	217.8	–	52.5	0.2
5	EMPSI-PRGE	Benefit Plans, Policy, and Wellness Programs (HR)	70,049	70,097	71,850	73,646	197.2	–	52.5	0.3
6	EMPSI-PRGF	Safety Assurance and PSEMS governance	154	158	162	166	0.44	–	48.8	110.8
7		Total	$169,818	$171,876	$174,936	$179,284				

(a) NPV uses a base year of 2023.

(b) CBR calculations include allocated Foundational Activity Program costs

For additional details see Exhibit (PG&E-7), WP EHS-EMPSI-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

2. Changes to Mitigations

PG&E will continue implementing the mitigations started in the 2024-2026 period. One foundational program enhancement and one new mitigation are planned for the 2027-2030 timeframe.

EMPSI-Ergonomics Program – Industrial Ergo Predictive Model (Foundational): This project supports planned control EMPSI-C019 and mitigation EMPSI-M019 and does not directly reduce the risk. The project involves the development and pilot of a predictive model to detect coworkers at high risk for developing an IE injury. This is dependent on implementing new ergonomics system software in 2024, time for data to be input and mature (2 years) and would not incur additional costs as the model would be developed internally and interventions would use resources already in place. Implementation timeframe is 2027 through 2030.

EMPSI-M019 - Ergonomics Program – Functional Movement Screenings (FMS): This mitigation implements a program for performing voluntary functional movement screenings for field-based coworkers to determine MSD deficiencies and design tailored strengthening/conditioning programs. Participants in the program may benefit from subsequent FMS screenings and interventions to improvement movement, especially in situations of return to work, job changes, and/or experienced work- or non-work-related injuries. A pilot of the FMS Program with the technology solution would be conducted in 2027 and if successful in improving FMS scores, a formal voluntary program would launch in 2028, with implementation through 2030. It be control EMPSI-C027 in 2031 as part of program EMPSI PRGD Employee Occupational Health and Wellness.

Table 3-10 below shows the cost estimates, risk reduction values, and CBRs for the mitigations planned for the 2027-2030 period.

TABLE 3-10
MITIGATION COST ESTIMATES, RISK REDUCTION, CBR, AND FACTORS AFFECTING SELECTION
2027-2030

			Thousands of Nominal Dollars				Millions of Dollars (NPV) [b]				
Line No.	Mitigation ID [a]	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Foundational Activity Cost [B]	Risk Reduction [C]	CBR[c] [C]/([A]+[B])	Factors Affecting Selection
1	EMPSI-M01B	PG&E Safety Excellence Management System (PSEMS)	$615	$1,615	$615	$615	$2.4	-	$14.1	5.8	
2	EMPSI-M016	Fit 4 You(Fit4U)Program	$477	$492	$506	$522	1.4	-	0.1	0.1	Risk Tolerance
3	EMPSI-M019	Ergonomics Program – Functional Movement Screenings	$356	$78	$80	$82	0.4	-	0.1	0.3	Risk Tolerance
4	CNTSI-M020, EMPSI-M020	SIF Capacity & Learning Model	$80	$82	-	-	0.1	-	1.4	12.1	
5		Total	$1,528	$2,267	$1,201	$1,219					

(a) Programs with multiple IDs apply to more than one risk. For these programs, the same information will be presented in all applicable risk chapter tables.

(b) NPV uses a base year of 2023.

(c) CBR calculations include allocated Foundational Activity Program costs.

For additional details see Exhibit (PG&E-7), WP EHS-EMPSI-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

3. Factors Affecting Selection

Based on the results of the risk modeling analysis shown in Table 3-10 above, PG&E is proposing to spend approximately 56 percent of 2027-2030 planned funding on the programs with the highest CBRs and highest risk reduction scores: continued PSEMS Implementation and operationalization and the implementation of the SIF Capacity and Learning model.

Occupation Health Programs have the lowest CBR and Risk Reduction scores. PG&E continues to support Occupation Health Programs because they help to minimize the workers' compensation injuries and injury severity.

Additional information on the rationale for selecting mitigations is provided below.

Risk Tolerance: The Commission has recognized the need for discussion and clear guidance on Risk Tolerance and has expressed its intention to address this topic in future Phases of the Risk OIR. In the meantime, PG&E's risk mitigation strategies are selected to ensure that safety remains PG&E's top priority even when the quantitative RAMP modelling indicates the costs are higher than the modeled value of risk reduction. The mitigations with CBR scores less than 1.0 are both designed to continue driving down employee workplace injury risks.

- The Fit4 U Program: Results evaluated thus far demonstrate a direct impact for reducing the risk of a DART case for those who participate in the program. The program piloted in 2018-2019 leveraged in-person services for most program components and resulted in a 2.3 percent positive difference for coworkers with DART cases between the pilot participants and the comparison group. In 2020-2021, an interim program solely leveraged virtual services and resulted in a 2.3 percent positive difference for coworkers with DART cases between the pilot participants and the comparison group. The overall mitigation effectiveness of 2.95 percent combines the above pilot and interim program results with the 3.6 percent positive results from a second component, the benchmarked program Fit4U was modeled after. With the small changes in scope of services offerings between the pilot, interim and program launching in 2024, evaluating effectiveness will continue as both the program and data matures, and the number of participants to evaluate increases. In addition, there may be longer term wellbeing benefits and reductions in Workers' Compensation claim costs and this will also continue be evaluated as the program matures.

- Ergonomics Program – Functional Movement Screenings (FMS): Is a best practice preventative intervention to reduce musculoskeletal injuries. FMS is a tool supported by moderate scientific evidence that can be used to predict injury potential by assessing movement dysfunction. Low FMS scores predictably indicate an increased risk of musculoskeletal injury. Results of FMS are used to develop tailored corrective exercises to improve movement and reduce injuries. This program aims to implement a technology solution for consistent and reliable FMS screenings and measurement of results. Participation in FMS screening and tailored corrective exercise programs will be voluntary, as the corrective exercises must be consistently performed by the employee during non-work hours. A pilot of the FMS program with the technology solution would be conducted in 2027 and if successful in improving FMS scores, a formal voluntary program would launch in 2028, with implementation through 2030.

E. Alternative Mitigations Analysis

In addition to the proposed mitigations described in Section E above, PG&E considered alternative mitigations as well. The mitigations described in Section E constitute the Proposed Plan. The Alternative Plans consist of a combination of all the proposed mitigations along with the alternative mitigation(s). PG&E describes each of the alternative mitigations it considered below and then provides a table showing the cost estimates, risk reduction values, and CBRs for each of the Alternative Plans.

1. Alternative Plan 1: EMPSI-A001 – Field Predictive Analytics

Alternative 1 considers implementing a software application that predicts threats to workers in advance and enables safe execution of work in the field. The application uses artificial intelligence to gauge the likelihood and severity of incidents before they occur and generate actionable intelligence through leveraging real-world data. The software can deliver a clear picture of risk up to a week in advance and enables decision makers to take action in the right place, at the right time, before an incident occurs. This mitigation was not chosen due to uncertainties with implementation costs.

TABLE 3-11
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030

			Thousands of Nominal Dollars				Millions Of Dollars (NPV)[(a)]		
Line No.	Mitigation ID	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	EMPSI-A001	Field Predictive Analytics	$2,200	$2,200	$2,200	$2,200	$6.1	$9.6	1.6
2		Total	$2,200	$2,200	$2,200	$2,200			

(a) NPV uses a base year of 2023.

For additional details see Exhibit (PG&E-7), WP EHS-EMPSI-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

2. Alternative Plan 2: EMPSI-A002 – AlertMeter® Implementation

Implement a cognitive impairment tool (AlertMeter®)[13] designed to help identify the alertness of the workforce and whether a coworker may be struggling with alertness or distracted to the point of creating a safety risk. This application has the potential to reduce exposure to both SIF incidents and non-SIF DART case incidents. This mitigation was not chosen due to uncertainties with implementation in the field employee population.

13 AlertMeter® Impairment Detection Tool | Geotab Marketplace (accessed May 6, 2024).

TABLE 3-12
ALTERNATIVE MITIGATION COST ESTIMATES, RISK REDUCTION, AND CBR
2027-2030

			Thousands of Nominal Dollars				Millions Of Dollars (NPV)[a]		
Line No.	Mitigation ID	Mitigation Name	2027	2028	2029	2030	Program Cost [A]	Risk Reduction [B]	CBR [B]/[A]
1	EMPSI-A002	AlertMeter® Implementation	$1,167	$1,167	$1,167	$1,167	$3.2	$6.0	1.8
2		Total	$1,167	$1,167	$1,167	$1,167			

(a) NPV uses a base year of 2023.

For additional details see Exhibit (PG&E-7), WP EHS-EMPSI-F.

The cost estimates in this table are generally based on PG&E's 2024 budget plan carried forward through 2030. See Exhibit (PG&E-1), Chapter 1, Section D.3.

Application: 24-05-
(U 39 G)
Exhibit No.: (PG&E-8)
Date: May 15, 2024
Witness(es): Various

PACIFIC GAS AND ELECTRIC COMPANY

2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT

EXHIBIT (PG&E-8)

APPENDICES

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2024 RISK ASSESSMENT AND MITIGATION PHASE REPORT
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PACIFIC GAS AND ELECTRIC COMPANY

APPENDIX A

ESJ PILOT STUDY PLAN

Pacific Gas & Electric's
Proposed Environmental and Social Justice
Pilot Study Plan

Introduction: PG&E understands and appreciates the responsibility of being the first IOU to propose an Environmental and Social Justice (ESJ) Pilot Study Plan (PSP) in the Risk-Based Decision-Making Framework (RDF). PG&E supports the Commission's desire to identify and address potential equity issues that may arise in the identification and mitigation of risks as directed in Decision, R.22-12-027[i] and identifies this PSP to be a key action item to implementing PG&E's Environmental and Social Justice Policy:

> At PG&E, Environmental and Social Justice means making better business decisions by understanding the impacts of our activities and investments on environmental and social justice communities, while providing more sustainable, inclusive and equitable customer solutions. Environmental and social justice communities consist of disadvantaged communities, low-income communities and historically marginalized racial and ethnic communities who have been disproportionately impacted by environmental hazards. To better serve environmental and social justice communities, we will:
>
> - Take responsibility for our actions and operations – past, present, and future.
> - Comply fully with the letter and spirit of all applicable environmental and social justice laws and regulations.
> - Actively seek community input and use data-driven tools to better understand potential cumulative impacts of PG&E business decisions and to prioritize our actions to help support sustainable communities.
> - Incorporate environmental and social justice considerations into our operations and energy delivery and maximize opportunities for small and diverse business in PG&E's supply chain.
> - Consider environmental and social justice impacts in our policy engagement to create opportunities for and minimize adverse effects on environmental and social justice communities.

- Educate our coworkers about our Environmental and Social Justice Policy and how to operationalize the policy in their work practices.
- Maintain open communication and seek opportunities to partner with our stakeholders on environmental and social justice concerns.
- Strengthen relationships with the Native American tribal governments and communities we serve and develop partnerships to better address their environmental concerns.
- Conduct our business in a manner that respects the human rights of all individuals, as outlined in our Human Rights Policy.

PG&E's proposed ESJ PSP envisions a targeted approach to assessing equity issues related to the seven Action Items called out in D.22-12-027.

- Action Item #1: Consider equity in the evaluation of Consequences and risk mitigation within the Risk-Based Decision-Making Framework (RDF), using the most current version of CalEnviroScreen to better understand how risks may disproportionately impact some communities more than others;
- Action Item #2: Consider investments in clean energy resources in the RDF, as possible means to improve safety and reliability and mitigate risks in Disadvantaged and Vulnerable Communities (DVCs);
- Action Item #3: Consider Mitigations that improve local air quality and public health in the RDF, including supporting data collection efforts associated with Assembly Bill 617 regarding community air protection program;
- Action Item #4: Evaluate how the selection of proposed mitigations in the RDF may impact climate resiliency in DVCs;
- Action Item #5: Evaluate if estimated impacts of wildfire smoke included in the RDF disproportionately impact DVCs;
- Action Item #6: Estimate the extent to which risk mitigation investments included in the RDF impact and benefit DVCs independently and in relation to non-DVCs in the IOU service territory;

- Action Item #7: Enhance outreach and public participation opportunities for DVCs to meaningfully participate in risk mitigation and climate adaptation activities consistent with Decision 20-08-046.

This proposed ESJ PSP describes PG&E's learning objectives for each Action Item, deliverable from each objective to be filed with the RAMP, and the proposed methods for addressing the learning objective. A final review of lessons learned from the ESJ PSP will be submitted via a White Paper consistent with the requirements of the Phase II Decision.

As part of the implementation of this PSP and consistent with its ESJ Policy, PG&E looks forward to engaging with the Commission's Energy Division, Disadvantaged Communities Advisory Group (DACAG), and Community-based Organizations Working Group (CBOWG) to improve its ESJ PSP. Further, as directed in the Phase II Decision, PG&E will notify and host a public workshop for feedback on these Action Items. PG&E appreciates the opportunity to receive feedback and engagement on its Pilot of the ESJ Action Items and will endeavor to incorporate and address all feedback received in these forums.

The following sections detail PG&E's proposed approach to advancing each of the seven ESJ Action Items in D.22-12-027.

I. <u>ACTION ITEM #1:</u> Consider equity in the evaluation of Consequences and risk mitigation within the Risk-Based Decision-Making Framework (RDF), using the most current version of CalEnviroScreen to better understand how risks may disproportionately impact some communities more than others.

Learning Objective: Pilot a process for identifying risk impacts and equity in risk reductions in Disadvantaged and Vulnerable Communities (DVC).

Deliverable: PG&E intends to obtain available location data on risk consequences and mitigations at the census tract-level for the Loss of Containment on a Gas Transmission Pipeline (LOCTM), Large Uncontrolled Water Release (LGUWR), and Wildfire (WLDFR) risks. Where a consequence or mitigation is identified as occurring in a DVC, an evaluation will be provided in the associated RAMP risk narrative.

Discussion: PG&E plans to deliver on this Action Item by matching asset location data from its GIS and Foundry software with the DVC criteria and CalEnviroScreen census tract identifiers to develop census tract-level, location-based, potential consequence data. Mitigation data, in most cases, is unexpected to have a location-based forecast in the GRC time period relevant to the RAMP. PG&E intends to use best available data and assumptions to provide insight into potential mitigation impacts to DVCs.

PG&E selects the risks WLDFR, LOCTM, and LGUWR for several reasons:

- Risks are expected to be relevant to multiple DVC criteria;
- Quality of consequence location data will allow for accurate CalEnviroScreen analysis; and
- Mitigation location may be predictable and relevant to DVC census tracts.

Mitigation projects may apply to large portions of PG&E's assets and worksite location which may not be defined prior to the GRC period due to other dependencies. Where possible, PG&E expects some qualitative assumptions may be necessary to address uniform or absent data.

II. ACTION ITEM #2: Consider investments in clean energy resources in the RDF, as possible means to improve safety and reliability and mitigate risks in DVCs.

Learning Objective: Improve capabilities for identifying and enabling investments in clean energy in DVCs.

Deliverable: PG&E will provide a section in its RAMP narrative explaining expected benefits of its Microgrid Incentive Program (MIP) and Community Microgrid Enablement Program (CMEP).

Discussion: PG&E expects this effort to most directly apply to its efforts in employing microgrids as an alternative local energy resilience solution pursuant to the Order Instituting Rulemaking Regarding Microgrids Pursuant to Senate Bill 1339 and Resiliency Strategies (Microgrids OIR, R.19-09-009).

PG&E will attempt to quantify the risk reductions of forecasted Microgrid projects to relevant RAMP risks, e.g., Electric Distribution Overhead (DOVHD). However, PG&E has not at this time attempted to apply Microgrid projects to the risk framework, so we are unable to commit to quantified improvements in safety and reliability.

PG&E is not currently constructing any additional generation facilities that would be relevant to this Action Item.

Tax-funded programs such as the solar incentive programs, electrification, and other low-income assistance programs are not relevant to the GRC, and thus are not planned to be covered in the RAMP.

III. <u>ACTION ITEM #3:</u> Consider Mitigations that improve local air quality and public health in the RDF, including supporting data collection efforts associated with Assembly Bill 617 regarding community air protection program.

Learning Objective: Integrate ongoing developments in Assembly Bill 617 (AB 617) to RAMP 2024.

Deliverable: PG&E will provide detail regarding mitigations in the 2024 RAMP period that are expected to reduce greenhouse gasses (GHG) emissions and local air pollutants.

Discussion: PG&E provides emissions reporting regarding GHG and local air pollutants released through its operations to the California Air Resource Board and applicable air quality management district. PG&E has a long history of reducing its GHG and local area pollutant emissions and will attempt to identify and analyze any additional GHG or pollutant mitigations applicable to the 2024 RAMP, including noting any applicability to a DVC or AB 617 communities. PG&E's 2022 Climate Strategy Report details the company's commitments to further reducing emissions in coming years.[1] Wildfire smoke considerations will be discussed in Action Item #5.

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[1] https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/pge-climate-goals/PGE-Climate-Strategy-Report.pdf

IV. ACTION ITEM #4: Evaluate how the selection of proposed mitigations in the RDF may impact climate resiliency in the DVCs.

Learning Objectives: Identification of climate resiliency efforts in DVCs.

Deliverable: PG&E will explain mitigations that impact climate resiliency in its RAMP and indicate relevant applications to DVCs.

Discussion: PG&E will expand on its 2020 RAMP analysis to provide a new Extreme Climate Scenario Pilot in its 2024 RAMP. Mitigations considered in this Pilot will provide a climate-risk weighted view as a point of discussion. Mitigations that are relevant to DVCs will be indicated and explained. Mitigations considered will also include projects for energy-resilience needs and preferences stated by community-based organizations and representatives in PG&E's Resilient Together outreach process being conducted pursuant to D. 20-08-046.

PG&E will also apply data obtained through its Climate Adaptation and Vulnerability Assessment (CAVA) to risks in the RAMP. Mitigations addressing CAVA applications will be identified and applied to the relevant risks. Where a DVC is impacted by a climate resiliency related mitigation in this way, it will also be identified and explained.

V. ACTION ITEM #5: Evaluate if estimated impacts of wildfire smoke included in the RDF disproportionately impact DVCs.

Learning Objective: Pilot wildfire smoke analysis methodologies that can potentially lead to identifying and evaluating impacts to DVCs.

Deliverable: PG&E will attempt to identify if any DVCs are disproportionately impacted by wildfire smoke.

Discussion: As stated in the Phase II Decision, PG&E will "use public studies of the health impacts of wildfire smoke available in 2023" to perform this analysis. PG&E has found consensus amongst IOUs and Intervening Parties[2] that there is currently insufficient capability to accurately model the impacts of wildfire smoke. Research to improve this modeling is outside of the scope of this RAMP and the capabilities of PG&E. Further, conversations regarding addressing modeling of wildfire smoke are ongoing with the CPUC, Level4Ventures, Energy Safety (OEIS), CalFire, MGRA, and many other parties important to the discussion.

To provide any estimated impacts of wildfire smoke in the 2024 RAMP, PG&E expects to make broad assumptions, and will make reasonable efforts to explain and justify those assumptions so external parties can follow model logic. PG&E will provide its highest level of accuracy and best effort considerations relevant to DVCs for the wildfire smoke estimations.

[2] "However it is important to emphasize that 1) wildfire fatality and morbidity numbers are highly uncertain and wildfire smoke affects populations depending on the ambient weather conditions at the time. A more useful and accurate estimation of utility wildfire smoke risk will require the development of new methodologies that can estimate plume dispersal and perform population impact analyses based upon epidemiological studies." Analysis of Utility Wildfire Risk Assessments and Mitigations in California Joseph Mitchell, March 7, 2023, Easy Chair Preprint No. 9840.

VI. <u>ACTION ITEM #6:</u> Estimate the extent to which risk mitigation investments included in the RDF impact and benefit DVCs independently and in relation to non-DVCs in the IOU service territory.

Learning Objective: Initiate a process to identify potential engrained inequities in implementation of mitigations.

Deliverable: Using the risk analysis in Action Item #1, PG&E will compare forecasted estimates for mitigations in the LOCTM, LGUWR, and WLDFR risks and draw relative comparisons to the impacts to DVC and non-DVC census tracts.

Discussion: As stated in Action Item #1, PG&E does not typically forecast the location of mitigations in the 3-7 year-out plan as will be necessary for the 2024 RAMP applying to the 2027 GRC test year. PG&E intends to use the best available data in the LOCTM, LGUWR, and WLDFR risk analyses along with assumptions about the expected work to provide a comparison of spend in DVC and non-DVC census tracts. Additionally, it should be noted that the physical location of mitigation investment is not always directly correlated to a local benefit given the networked nature of the energy system and modeled downstream consequence impacts. PG&E will provide explanation to mitigations that are believed to be relevant to DVCs when the spending is not directly located in the DVC.

VII. ACTION ITEM #7: Enhance outreach and public participation opportunities for DVCs to meaningfully participate in risk mitigation and climate adaptation activities consistent with Decision 20-08-046.

Learning Objective: Actively seek community input to better understand potential impacts of PG&E business decisions.

Deliverable: PG&E will provide its Climate Vulnerability Assessment (CVA) Community Engagement Plan (CEP) in May 2023. PG&E will also publicly notice a workshop for this ESJ PSP, the CVA CEP, and advance comment on PG&E's Phase I and Phase II Decisions implementation for its 2024 RAMP filing prior to the end of Q3 2023. Further, PG&E will publicly notice a workshop for the Cost-Benefit Approach and for a Pre-RAMP Workshop.

Discussion: PG&E considers this Action Item to be providing forums to discuss development of its CVA CEP, Cost-Benefit Approach, and this PSP with the public and interested parties and with the Commission's Energy Division to coordinate feedback from the DACAG and CBOWG. PG&E will also host at least one public workshop on these topics as required by the Phase II Decision and Decision 20-08-046, likely also utilizing the existing internal forum hosted by PG&E, the Community Perspectives Advisory Group. PG&E endeavors to be collaborative in the multiple new requirements covered in the Phase I and Phase II Decisions of the RDF OIR and intends to incorporate feedback from external parties to the best of its ability as it develops and files the 2024 RAMP.

PACIFIC GAS AND ELECTRIC COMPANY
RISK ASSESSMENT AND MITIGATION PHASE
APPENDIX B
RISK MODELING ACRONYMS

PACIFIC GAS AND ELECTRIC COMPANY RISK ASSESSMENT AND MITIGATION PHASE APPENDIX B RISK MODELING ACRONYMS

TABLE B-1
GLOSSARY OF RISK MODELING ACRONYMS

A

ATWACC	After Tax Weighted Average Cost of Capital

B

BLS	Bureau of Labor Statistics **or** U.S. Bureau of Labor Statistics

C

C&I	Commercial and Industrial
CAIDI	Customer Average Interruption Duration Index
Cal PA	California Public Advocates Office
CAT	Catastrophe (Bond)
CBA	Cost-Benefit Approach
CBR	Cost-Benefit Ratio
CMI	Customer Minutes Interrupted
CCF	Cross-Cutting Factor
CoRE	Consequence of a Risk Event
CPI-U	Consumer Price Index for All Urban Consumers
CRR	Corporate Risk Register
CERP	Company Emergency Response Plan

D

DOT	Department of Transportation **or** U.S. Department of Transportation
DVC	Disadvantaged Vulnerable Community

E

EF	Equivalent Fatality
EPSS	Enhanced Powerline Safety Settings
ESJ	Environmental and Social Justice
EOC	Emergency Operations Center

F

FA	Functional Area (previously “Line of Business”)

TABLE B-1
GLOSSARY OF RISK MODELING ACRONYMS

G

GDP	Gross Domestic Product
GRC	General Rate Case

H

HHS	Department of Health and Human Services **or** U.S. Department of Health and Human Services

I

ICE	Interruption Cost Estimate
IOU	Investor-Owned Utility

J

K

L

LOC	Loss of Containment
LoRE	Likelihood of a Risk Event

M

MAIS	Maximum Abbreviated Injury Scale
MAVF	Multi-Attribute Value Function (can be used as lowercase)
MGRA	Mussey Grade Road Alliance
MWh	Megawatt-Hour
MUWE	Median Usual Weekly Earnings

N

NPV	Net Present Value
NRC	Nuclear Regulatory Commission **or** U.S. Nuclear Regulatory Commission

O

OIR	Order Instituting Rulemaking

P

PVRR	Present Value of Revenue Requirement
PSPS	Public Safety Power Shutoff

TABLE B-1
GLOSSARY OF RISK MODELING ACRONYMS

Q

R

RDF	Risk-Based Decision-Making Framework
RAMP	Risk Assessment and Mitigation Phase
RIM	Records and Information Management

S

SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
S-MAP or SMAP	Safety Model Assessment Proceeding
SME	Subject Matter Expert (can be used as lowercase)
SOPP	Storm Outage Prediction Program
SPD	Safety Policy Division

T

TY	Test Year
TURN	The Utility Reform Network

U

V

VGA	Value of Gas Reliability Attribute
VSL	Value of a Statistical Life

W

WACC	Weighted Average Cost of Capital
WP	Workpaper